BP PLC
Form 20-F
March 04, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

(Mark One)

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended 31 December 2008

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

o **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-6262

BP p.l.c.
(Exact name of Registrant as specified in its charter)
England and Wales
(Jurisdiction of incorporation or organization)
1 St James s Square,
London SW1Y 4PD
United Kingdom
(Address of principal executive offices)

Dr Byron E Grote
BP p.l.c. 1 St James s Square,
London SW1Y 4PD
United Kingdom
Tel +44 (0) 20 7496 4000
Fax +44 (0) 20 7496 4630
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**New York Stock Exchange***
4 7/8% Guaranteed Notes due 2010	**New York Stock Exchange**
Floating Rate Guaranteed Extendible Notes	**New York Stock Exchange**
Floating Rate Guaranteed Notes due 2010	**New York Stock Exchange**
	New York Stock Exchange

Substitute Floating Rate Guaranteed Notes due July 10 2009	
Substitute Floating Rate Guaranteed Notes due October 9 2009	**New York Stock Exchange**
5.25% Guaranteed Notes due 2013	**New York Stock Exchange**

*Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary Shares of 25c each	**18,730,307,315**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes þ No o

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes o No þ

Note Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing: International Financial Reporting Standards as issued by the

U.S. GAAP o International Accounting Standards Board þ Other o

If Other has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 o Item 18 o

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No þ

Cross reference to Form 20-F

Contents

Certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Oil and natural gas reserves

Oil and gas reserves

Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 410(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.

(iii) Estimates of proved reserves do not include the following:

(a) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed reserves

Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves

Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Performance review

Performance review

Selected financial and operating information
This information, insofar as it relates to 2008, has been extracted or derived from the audited financial statements of the BP group presented on pages 99-184. Note 1 to the Financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related Notes elsewhere herein.
BP sold its Innovene operations in December 2005. In the circumstances of discontinued operations, IFRS require that the profits earned by the discontinued operations, in this case the Innovene operations, on sales to the continuing operations be eliminated on consolidation from the discontinued operations and attributed to the continuing operations and vice versa.

					$ million except per share amount
	2008	2007	2006	2005	200
come statement data					
otal revenues[a]	**365,700**	288,951	270,602	243,948	194,91
rofit before interest and taxation from continuing operations[a]	**35,239**	32,352	35,658	32,182	25,74
rofit from continuing operations[a]	**21,666**	21,169	22,626	22,133	17,88
rofit for the year	**21,666**	21,169	22,601	22,317	17,26
rofit for the year attributable to BP shareholders	**21,157**	20,845	22,315	22,026	17,07
apital expenditure and acquisitions[b]	**30,700**	20,641	17,231	14,149	16,65
er ordinary share cents					
rofit for the year attributable to BP shareholders					
asic	**112.59**	108.76	111.41	104.25	78.2
iluted	**111.56**	107.84	110.56	103.05	76.8
rofit from continuing operations attributable to BP shareholders[a]					
asic	**112.59**	108.76	111.54	103.38	81.0
iluted	**111.56**	107.84	110.68	102.19	79.6
ividends paid per share cents	**55.05**	42.30	38.40	34.85	27.7
pence	**29.387**	20.995	21.104	19.152	15.25
rdinary share data[c]					
verage number outstanding of 25 cent ordinary shares (shares million undiluted)	**18,790**	19,163	20,028	21,126	21,82
verage number outstanding of 25 cent ordinary shares (shares million diluted)	**18,963**	19,327	20,195	21,411	22,29
alance sheet data					
otal assets	**228,238**	236,076	217,601	206,914	194,63
et assets	**92,109**	94,652	85,465	80,450	78,23
hare capital	**5,176**	5,237	5,385	5,185	5,40
P shareholders equity	**91,303**	93,690	84,624	79,661	76,89
nance debt due after more than one year	**17,464**	15,651	11,086	10,230	12,90
et debt to net debt plus equity[d]	**21%**	22%	20%	17%	22

[a]Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations in 2004, 2005 and 2006.

[b]2008 included capital expenditure of $2,822 million and an asset exchange of $1,909 million, both in respect of our transaction with Husky, as well as capital expenditure of $3,667 million in respect of our transactions with Chesapeake (see page 47). 2007 included $1,132 million for the acquisition of Chevron s Netherlands manufacturing company. Capital expenditure in 2006 included $1 billion in respect of our investment in Rosneft. Capital expenditure and acquisitions for 2004 included $1,354 million for including TNK s interest in Slavneft

within TNK-BP and $1,355 million for the acquisition of Solvay s interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America. With the exception of the shares issued to Alfa Group and Access Renova (AAR) in connection with TNK-BP (2004-2006), all capital expenditure and acquisitions during the past five years have been financed from cash flow from operations, disposal proceeds and external financing.

[c]The number of ordinary shares shown has been used to calculate per share amounts.

[d]Net debt and the ratio of net debt to net debt plus equity ratio are non-GAAP measures. We believe that these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash

and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. Net debt has been redefined to include the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . Amounts for comparative periods are presented on a consistent basis.

Revised definition of net debt

				$ million
	2007	2006	2005	2004
As reported				
Net debt	27,483	21,420	16,202	21,732
Equity	94,652	85,465	80,450	78,235
Ratio of net debt to net debt plus equity	23%	20%	17%	22%
As amended				
Net debt	26,817	21,122	16,373	21,732
Equity	94,652	85,465	80,450	78,235
Ratio of net debt to net debt plus equity	22%	20%	17%	22%

Performance review

Production and net proved oil and natural gas reserves

The following table shows our production for the past five years and the estimated net proved oil and natural gas reserves at the end of each of those years.

Production and net proved reserves[a]

	2008[f]	2007	2006	2005	20
ude oil production for subsidiaries (thousand barrels per day)	**1,263**	1,304	1,351	1,423	1,4
ude oil production for equity-accounted entities (thousand barrels per day)	**1,138**	1,110	1,124	1,139	1,0
ural gas production for subsidiaries (million cubic feet per day)	**7,277**	7,222	7,412	7,512	7,6
ural gas production for equity-accounted entities (million cubic feet per day)	**1,057**	921	1,005	912	8
imated net proved crude oil reserves for subsidiaries (million barrels)[b]	**5,665**	5,492	5,893	6,360	6,7
imated net proved crude oil reserves for equity-accounted entities (million barrels)[c]	**4,688**	4,581	3,888	3,205	3,1
imated net proved natural gas reserves for subsidiaries (billion cubic feet)[d]	**40,005**	41,130	42,168	44,448	45,6
imated net proved natural gas reserves for equity-accounted entities (billion cubic feet)[e]	**5,203**	3,770	3,763	3,856	2,8

[a]Crude oil includes natural gas liquids (NGLs) and condensate. Production and proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include minority interests in consolidated operations.

[b]Includes 21 million barrels (20 million barrels at 31 December 2007 and 23 million

barrels at 31 December 2006) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[c]Includes 216 million barrels (210 million barrels at 31 December 2007 and 179 million barrels at 31 December 2006) in respect of the 6.80% minority interest in TNK-BP (6.51% at 31 December 2007 and 6.29% at 31 December 2006).

[d]Includes 3,108 billion cubic feet of natural gas (3,211 billion cubic feet at 31 December 2007 and 3,537 billion cubic feet at 31 December 2006) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[e]Includes 131 billion cubic feet (68 billion cubic feet at 31 December 2007 and 99 billion cubic feet at 31 December 2006) in respect of the 5.92% minority interest in TNK-BP (5.88% at 31 December 2007 and 7.77% at 31

December 2006).

[f]BP estimates proved reserves for reporting purposes in accordance with SEC rules and relevant guidance. As currently required, these proved reserve estimates are based on prices and costs as of the date the estimate is made. There was a rapid and substantial decline in oil prices in the fourth quarter of 2008 that was not matched by a similar reduction in operating costs by the end of the year. BP does not expect that these economic conditions will continue. However, our 2008 reserves are calculated on the basis of operating activities that would be undertaken were year-end prices and costs to persist.

During 2008, 1,085 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP s proved reserves for subsidiaries (excluding purchases and sales). After allowing for production, which amounted to 937mmboe, BP s proved reserves for subsidiaries were 12,562mmboe at 31 December 2008. These proved reserves are mainly located in the US (44%), Rest of Americas (17%), Asia Pacific (10%), Africa (11%) and the UK (8%).

For equity-accounted entities, 646mmboe were added to proved reserves (excluding purchases and sales), production was 491mmboe and proved reserves were 5,585mmboe at 31 December 2008.

*Natural gas is converted to oil equivalent at 5.8 billion cubic

feet (bcf) =
1 million barrels.

Performance review

Risk factors

We urge you to consider carefully the risks described below. If any of these risks occur, our business, financial condition and results of operations could suffer and the trading price and liquidity of our securities could decline, in which case you could lose all or part of your investment.

In the current global financial crisis and uncertain economic environment, certain risks may gain more prominence either individually or when taken together. Oil and gas prices and margins are likely to remain lower than in recent times due to reduced demand; the impact of this situation will also depend on the degree to which producers reduce production. At the same time, governments will be facing greater pressure on public finances leading to the risk of increased taxation. These factors may also lead to intensified competition for market share and available margin, with consequential potential adverse effects on volumes. The financial and economic situation may have a negative impact on third parties with whom we do, or may do, business. Any of these factors may affect our results of operations, financial condition and liquidity.

If there is an extended period of constraint in the capital markets, with debt markets in particular experiencing lack of liquidity, at a time when cash flows from our business operations may be under pressure, this may impact our ability to maintain our long-term investment programme with a consequent effect on our growth rate, and may impact shareholder returns, including dividends and share buybacks, or share price. Decreases in the funded levels of our pension plans may also increase our pension funding requirements.

Our system of risk management provides the response to risks of group significance through the establishment of standards and other controls. Inability to identify, assess and respond to risks through this and other controls could lead to an inability to capture opportunities, threats materializing, inefficiency and non-compliance with laws and regulations.

The risks are categorized against the following areas: strategic; compliance and control; and operational.

Strategic risks

Access and renewal

Successful execution of our group plan depends critically on implementing activities to renew and reposition our portfolio. The challenges to renewal of our upstream portfolio are growing due to increasing competition for access to opportunities globally. Lack of material positions in new markets and/or inability to complete disposals could result in an inability to grow or even maintain our production.

Prices and markets

Oil, gas and product prices are subject to international supply and demand. Political developments and the outcome of meetings of OPEC can particularly affect world supply and oil prices. Previous oil price increases have resulted in increased fiscal take, cost inflation and more onerous terms for access to resources. As a result, increased oil prices may not improve margin performance. In addition to the adverse effect on revenues, margins and profitability from any fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to further reviews for impairment of the group s oil and natural gas properties. Such reviews would reflect management s view of long-term oil and natural gas prices and could result in a charge for impairment that could have a significant effect on the group s results of operations in the period in which it occurs. Rapid material and/or sustained change in oil, gas and product prices can impact the validity of the assumptions on which strategic decisions are based and, as a result, the ensuing actions derived from those decisions may no longer be appropriate. A prolonged period of low oil prices may impact our ability to maintain our long-term investment programme with a consequent effect on our growth rate and may impact shareholder returns, including dividends and share buybacks, or share price.

Periods of global recession could impact the demand for our products, the prices at which they can be sold and affect the viability of the markets in which we operate.

Refining profitability can be volatile, with both periodic oversupply and supply tightness in various regional markets. Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the petrochemicals market, with a consequent effect on prices and profitability.

Climate change and carbon pricing

Compliance with changes in laws, regulations and obligations relating to climate change could result in substantial capital expenditure, reduced profitability from changes in operating costs, and revenue generation and strategic growth opportunities being impacted.

Socio-political

We have operations in countries where political, economic and social transition is taking place. Some countries have experienced political instability, changes to the regulatory environment, expropriation or nationalization of property, civil strife, strikes, acts of war and insurrections. Any of these conditions occurring could disrupt or terminate our operations, causing our development activities to be curtailed or terminated in these areas or our production to decline and could cause us to incur additional costs. In particular, our investments in Russia could be adversely affected by heightened political and economic environment risks.

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. If it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate, our reputation and shareholder value could be damaged.

Competition

The oil, gas and petrochemicals industries are highly competitive. There is strong competition, both within the oil and gas industry and with other industries, in supplying the fuel needs of commerce, industry and the home. Competition puts pressure on product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency. The implementation of group strategy requires continued technological advances and innovation including advances in exploration, production, refining, petrochemicals manufacturing technology and advances in technology related to energy usage. Our performance could be impeded if competitors developed or acquired intellectual property rights to technology that we required or if our innovation lagged the industry.

Investment efficiency

Our organic growth is dependent on creating a portfolio of quality options and investing in the best options. Ineffective investment selection could lead to loss of value and higher capital expenditure.

Reserves replacement

Successful execution of our group strategy depends critically on sustaining long-term reserves replacement. If upstream resources are not progressed to proved reserves in a timely and efficient manner, we will be unable to sustain long-term replacement of reserves.

Performance review

Liquidity, financial capacity and financial exposure
The group has established a financial framework to ensure that it is able to maintain an appropriate level of liquidity and financial capacity and to constrain the level of assessed capital at risk for the purposes of positions taken in financial instruments. Failure to operate within our financial framework could lead to the group becoming financially distressed leading to a loss of shareholder value. Commercial credit risk is measured and controlled to determine the group s total credit risk. Inability to determine adequately our credit exposure could lead to financial loss. A credit crisis affecting banks and other sectors of the economy could impact the ability of counterparties to meet their financial obligations to the group. It could also affect our ability to raise capital to fund growth.

Crude oil prices are generally set in US dollars, while sales of refined products may be in a variety of currencies. Fluctuations in exchange rates can therefore give rise to foreign exchange exposures, with a consequent impact on underlying costs and revenues.

For more information on financial instruments and financial risk factors see Financial statements Note 28 on page 140 and Note 34 on page 148.

Compliance and control risks

Regulatory
The oil industry is subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental and health and safety protection controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. We buy, sell and trade oil and gas products in certain regulated commodity markets. The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities, and operates in certain tax jurisdictions that have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, or we could incur additional costs.

For more information on environmental regulation, see Environment on page 39.

Ethical misconduct and non-compliance
Our code of conduct, which applies to all employees, defines our commitment to integrity, compliance with all applicable legal requirements, high ethical standards and the behaviours and actions we expect of our businesses and people wherever we operate. Incidents of ethical misconduct or non-compliance with applicable laws and regulations could be damaging to our reputation and shareholder value. Multiple events of non-compliance could call into question the integrity of our operations.

For certain legal proceedings involving the group, see Legal proceedings on page 88.

Liabilities and provisions
Changes in the external environment, such as new laws and regulations, market volatility or other factors, could affect the adequacy of our provisions for pensions, tax, environmental and legal liabilities.

Reporting
External reporting of financial and non-financial data is reliant on the integrity of systems and people. Failure to report data accurately and in compliance with external standards could result in regulatory action, legal liability and damage to our reputation.

Operational risks

Process safety
Inherent in our operations are hazards that require continuous oversight and control. There are risks of technical integrity failure and loss of containment of hydrocarbons and other hazardous material at operating sites or pipelines. Failure to manage these risks could result in injury or loss of life, environmental damage, or loss of production and could result in regulatory action, legal liability and damage to our reputation.

Personal safety

Inability to provide safe environments for our workforce and the public could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to our reputation.

Environmental

If we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment, we could fail to live up to our aspirations of no or minimal damage to the environment and contributing to human progress.

Security

Security threats require continuous oversight and control. Acts of terrorism against our plants and offices, pipelines, transportation or computer systems could severely disrupt business and operations and could cause harm to people.

Product quality

Supplying customers with on-specification products is critical to maintaining our licence to operate and our reputation in the marketplace. Failure to meet product quality standards throughout the value chain could lead to harm to people and the environment and loss of customers.

Drilling and production

Exploration and production require high levels of investment and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. The cost of drilling, completing or operating wells is often uncertain. We may be required to curtail, delay or cancel drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

Transportation

All modes of transportation of hydrocarbons contain inherent risks. A loss of containment of hydrocarbons and other hazardous material could occur during transportation by road, rail, sea or pipeline. This is a significant risk due to the potential impact of a release on the environment and people and given the high volumes involved.

Major project delivery

Successful execution of our group plan (*see page 11*) depends critically on implementing the activities to deliver the major projects over the plan period. Poor delivery of any major project that underpins production growth and/or a major programme designed to enhance shareholder value could adversely affect our financial performance.

Digital infrastructure

The reliability and security of our digital infrastructure are critical to maintaining our business applications availability. A breach of our digital security could cause serious damage to business operations and, in some circumstances, could result in injury to people, damage to assets, harm to the environment and breaches of regulations.

Performance review

Business continuity and disaster recovery
Contingency plans are required to continue or recover operations following a disruption or incident. Inability to restore or replace critical capacity to an agreed level within an agreed timeframe would prolong the impact of any disruption and could severely affect business and operations.
Crisis management
Crisis management plans and capability are essential to deal with emergencies at every level of our operations. If we do not respond or are perceived not to respond in an appropriate manner to either an external or internal crisis, our business and operations could be severely disrupted.
People and capability
Employee training, development and successful recruitment of new staff, in particular petroleum engineers and scientists, are key to implementing our plans. Inability to develop the human capacity and capability across the organization could jeopardize performance delivery.
Treasury and trading activities
In the normal course of business, we are subject to operational risk around our treasury and trading activities. Control of these activities is highly dependent on our ability to process, manage and monitor a large number of complex transactions across many markets and currencies. Shortcomings or failures in our systems, risk management methodology, internal control processes or people could lead to disruption of our business, financial loss, regulatory intervention or damage to our reputation.
Forward-looking statements
In order to utilize the Safe Harbor provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as will , expects , is expected to , aims , should , may , objective , is likely to , intends , believes , plan
expressions. In particular, among other statements, (i) certain statements in Performance review (*pages 6-56*) with regard to strategy, management aims and objectives, future capital expenditure, future hydrocarbon production volume, date(s) or period(s) in which production is scheduled or expected to come onstream or a project or action is scheduled or expected to begin or be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Performance review (*pages 6-45*) with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Performance review (*pages 46-59*) with regard to the plans of the group, the cost of and provision for future remediation programmes, taxation, liquidity and costs for providing pension and other post-retirement benefits; and including under Liquidity and capital resources with regard to oil prices, production, demand for refining products, refining volumes and margins and impact on the petrochemicals sector, refining availability, continuing priority of safe, compliant and reliable operations, and focus on cost efficiency, cost deflation, capital expenditure, expected disposal proceeds, cash flows, shareholder distributions, gearing, working capital, guarantees, expected payments under contractual and commercial commitments and purchase obligations; are all forward-looking in nature.
By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; the timing of bringing new fields onstream; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under Risk factors on pages 8-10. In addition to factors set forth

elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to BP s competitive position are based on the company s belief and, in some cases, rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

Performance review

Information on the company

General

Unless otherwise indicated, information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including minority interests. Also, unless otherwise indicated, figures for total revenues include sales between BP businesses.

The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001.

BP is one of the world s leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located at 1 St James s Square, London SW1Y 4PD, UK, tel +44 (0)20 7496 4000. Our agent in the US is BP America Inc., 501 Westlake Park Boulevard, Houston, Texas 77079, tel +1281 366 2000.

Overview of the group

BP is a global group, with interests and activities held or operated through subsidiaries, jointly controlled entities or associates established in, and subject to the laws and regulations of, many different jurisdictions. These interests and activities covered two business segments in 2008: Exploration and Production and Refining and Marketing. With effect from 1 January 2008, the former Gas, Power and Renewables segment ceased to report separately (see Resegmentation in 2008 on page 12).

A separate business, Alternative Energy, reported in Other businesses and corporate, handles BP s low-carbon businesses and future growth options outside oil and gas.

Exploration and Production s activities include oil and natural gas exploration, development and production (upstream activities), together with related pipeline, transportation and processing activities (midstream activities), as well as the marketing and trading of natural gas (including LNG), power and natural gas liquids (NGLs). The activities of Refining and Marketing include the refining, manufacturing, supply and trading, marketing and transportation of crude oil, petroleum and petrochemicals products and related services. The group provides high-quality technological support for all its businesses through its research and engineering activities.

All these activities are supported by a number of other organizational elements comprising group functions and regions. Group functions serve the business segments, aiming to achieve coherence across the group, manage risks effectively and achieve economies of scale. In addition, each regional head provides the required integration and co-ordination of group activities and represents BP to external parties.

Internal control

The group s system of internal control is designed to meet the expectations of internal control of the Combined Code in the UK and of COSO (committee of the sponsoring organizations for the Treadway Commission) in the US. The system of internal control is the complete set of management systems, organizational structures, processes, standards and behaviours that are employed to conduct the business of BP and deliver returns to shareholders. The design of the system of internal control addresses risks and how to respond to them. Each component of the system is in itself a device to respond to a particular type or collection of risks.

Strategy

The group strategy describes the group s strategic objectives and the assumptions made by BP about the future. It describes strategic risks and opportunities that arise from making such assumptions and the actions to be taken to manage or mitigate the risks. The board delegates to the group chief executive responsibility for developing BP s strategy and its implementation through the group plan that determines the setting of priorities and allocation of resources. The group chief
executive is obliged to discuss with the board, on the basis of the strategy and group plan, all material matters currently or prospectively affecting BP s performance

During 2008, we continued to pursue our three strategic priorities of Safety , People and Performance , which underpin BP s forward agenda .

Through this, we have taken steps to restore revenues, reduce complexity and manage costs and have made significant progress towards closing the competitive performance gap to our peer group. Looking forward, our strategy is to create value for shareholders by investing to deliver growth in Exploration and Production, together with high-quality earnings and returns throughout our operations. Our first priority will always be to ensure the safety and integrity of our operations.

We expect Exploration and Production to be our core source of growth. We intend to re-invest competitively in Exploration and Production to secure and grow high-quality oil and gas resources. This investment is intended to be focused on strengthening our position further by securing new access and achieving exploration success. It is also intended to be targeted on a renewed focus on increasing recovery from fields in which we already operate. We expect to make investment across the full life cycle of our assets with an increased emphasis on technology as a source of productivity, access and competitive advantage.

In Refining and Marketing, we expect to continue building our business around advantaged assets in material and significant energy markets. We intend to continue investing in improving the safety and reliability of our operations. Additionally, we intend to drive further operational performance and productivity by investing in the upgrade of manufacturing capabilities within our integrated fuels value chains. We also intend to invest selectively in international businesses, including lubricants and petrochemicals, where we believe there is the potential to deliver strong returns.

In Alternative Energy, we are focusing our investment activity in new energy technology and low-carbon energy businesses that we believe will provide long-term options to meet energy demand and provide BP with significant long-term growth potential. These are wind, solar, biofuels and carbon capture and storage.

We are dependent on our people and technology to deliver on our strategy. We intend to invest in ensuring that we have people with the right capability and experience to meet all of our objectives and the technology to support the delivery of competitive business performance and new business development. BP is committed to delivering its strategy by operating safely, reliably, in compliance with the law and within the discipline of a clear financial framework.

Geographical presence

We have well-established operations in Europe, the US, Canada, Russia, South America, Australasia, Asia and parts of Africa. Currently, around 67% of the group s capital is invested in Organisation for Economic Cooperation and Development (OECD) countries, with around 41% of our fixed assets located in the US and around 20% located in Europe.

We believe that BP has a strong portfolio of assets:

In Exploration and Production, we have upstream interests in 29 countries. Exploration and Production activities are managed through operating units that are accountable for the day-to-day management of the segment s activities. An operating unit is accountable for one or more fields. Our current areas of major development include the deepwater Gulf of Mexico, Azerbaijan, Algeria, Angola, Egypt and Asia Pacific where we believe we have competitive advantage and the foundation for volume growth and improved margins in the future. We also have significant midstream activities to support our upstream interests. Additionally, we undertake natural gas, power and NGLs marketing and trading activity and LNG activity, which are focused on identifying and capturing worldwide opportunities for our upstream natural gas reserves, and we have an NGLs processing business in North America.

Performance review

In Refining and Marketing, we have a strong presence in the US and Europe. In the US, we market under the Amoco and BP brands in the midwest, east and south-east and under the ARCO brand on the west coast, and in Europe, under the BP and Aral brands. We have a long-established supply and trading activity responsible for delivering value across the crude and oil products supply chain. Our Aromatics & Acetyls business maintains a manufacturing position globally, with emphasis on growth in Asia. We also have, or are growing, businesses elsewhere in the world under the BP and Castrol brands, including a strong global lubricants portfolio and other business-to-business marketing businesses (aviation and marine) covering the mobility sectors. We continue to seek opportunities to broaden our activities in growth markets such as China and India.

Through non-US subsidiaries or other non-US entities, during the period covered by this report, BP conducted limited marketing, licensing and trading activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of Terrorism. BP believes that these activities are immaterial to the group.

BP has interests in, and is the operator of, two fields and a pipeline located outside Iran in which the National Iranian Oil Company (NIOC) and an affiliated entity have interests. In Iran, BP buys small quantities of crude oil. This is primarily for sale to third parties in Europe and a small portion is used by BP in its own refineries in South Africa and Europe. In addition, BP sells small quantities of crude oil into Iran and blends and markets small quantities of lubricants for sale to domestic consumers through a joint venture there, which has a blending facility. However, BP does not seek to obtain from the government of Iran licences or agreements for oil and gas projects in Iran, is not conducting any technical studies in Iran and does not own or operate any refineries or chemicals plants in Iran.

BP sells small quantities of lubricants in Cuba through a 50/50 joint venture there. In Syria, small quantities of lubricants are sold through a distributor and BP obtains small volumes of crude oil supplies for sale to third parties in Europe. In addition, BP sells small quantities of crude oil into Syria. These sales and purchases are insignificant and BP does not provide other goods, technologies or services in these countries.

Market context

Our market is a complex and fast-moving environment. In 2008, volatile energy price movements mirrored unsettled financial markets and wider economic uncertainty (*see Risk factors on page 8).* World oil consumption fell in 2008, with growing demand in fast growing non-OECD countries more than offset by falling consumption in the OECD countries. Gas consumption grew in the major markets. Anxieties around energy security continued, with individual consumer countries facing specific issues related to cost, geography and political relationships with producers. In terms of supply, substantial global reserves of oil and gas are in place but government, energy companies and industry must work together to bring these to market. There is also a clear need for greater energy diversity to address the competing challenges of growing demand and climate change. In terms of human resources, the energy industry also faces a shortage of professionals such as petroleum engineers and scientists.

Acquisitions and disposals

There were no significant acquisitions in 2006, 2007 or 2008.

In 2008, we completed an asset exchange with Husky Energy Inc., and asset purchases from Chesapeake Energy Corporation as described on page 47.

In 2007, BP acquired Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5MW wind farm co-located at the refinery as well as a 22.8% shareholding in the TEAM joint venture terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Disposal proceeds were $4,267 million, which included $1,903 million from the sale of the Coryton refinery and $605 million from the sale of our exploration and production gas infrastructure business in the Netherlands.

In 2006, BP purchased 9.6% of the shares issued under Rosneft s IPO for a consideration of $1 billion (included in capital expenditure). This represented an interest of around 1.4% in Rosneft. Disposal proceeds were $6,254 million, which included $2.1 billion on the sale of our interest in the Shenzi discovery and around $1.3 billion from the sale of our producing properties on the Outer Continental Shelf of the Gulf of Mexico to Apache Corporation.

Resegmentation in 2008

On 11 October 2007, BP announced that it was to simplify its organizational structure by reducing the number of business segments.

From 1 January 2008, BP has two business segments: Exploration and Production and Refining and Marketing. A separate business, Alternative Energy, handles BP s low-carbon businesses and future growth options outside oil and gas and reports under Other businesses and corporate.

As a result, and with effect from 1 January 2008:

- The former Gas, Power and Renewables segment ceased to report separately.
- The NGLs, LNG and gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.
- The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.
- The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Biofuels business was transferred from Refining and Marketing to Alternative Energy (which is reported in Other businesses and corporate).
- The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

Performance review

Exploration and Production

Our Exploration and Production segment includes upstream and midstream activities in 29 countries, including Angola, Azerbaijan, Canada, Egypt, Russia, Trinidad & Tobago (Trinidad), the UK, the US and locations within Asia Pacific, Latin America, North Africa and the Middle East, as well as gas marketing and trading activities, primarily in Canada, Europe, the UK and the US. Upstream activities involve oil and natural gas exploration and field development and production. Our exploration programme is currently focused around Algeria, Angola, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, Libya, the North Sea and onshore US. Major development areas include Algeria, Angola, Asia Pacific, Azerbaijan, Egypt and the deepwater Gulf of Mexico. During 2008, production came from 21 countries. The principal areas of production are Angola, Asia Pacific, Azerbaijan, Egypt, Latin America, the Middle East, Russia, Trinidad, the UK and the US.

Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our NGL extraction businesses in the US and UK. Our most significant midstream pipeline interests are the Trans-Alaska Pipeline System in the US, the Forties Pipeline System and the Central Area Transmission System pipeline, both in the UK sector of the North Sea, and the Baku-Tbilisi-Ceyhan pipeline, running through Azerbaijan, Georgia and Turkey. Major LNG activities are located in Trinidad, Indonesia and Australia. BP is also investing in the LNG business in Angola.

Additionally, our activities include the marketing and trading of natural gas, power and natural gas liquids in the US, Canada, UK and Europe. These activities provide routes into liquid markets for BP s gas and power, and generate margins and fees associated with the provision of physical and financial products to third parties and additional income from asset optimization and trading.

Our oil and natural gas production assets are located onshore and offshore and include wells, gathering centres, in-field flow lines, processing facilities, storage facilities, offshore platforms, export systems (e.g. transit lines), pipelines and LNG plant facilities.

Upstream operations in Argentina, Bolivia, Abu Dhabi, Kazakhstan and TNK-BP and some of the Sakhalin operations in Russia, as well as some of our operations in Canada, Indonesia and Venezuela, are conducted through equity-accounted entities.

Our performance in 2008

Profit before interest and tax for 2008 was $37.9 billion, an increase of 37% compared with 2007. The increase was primarily driven by higher oil and gas realizations. Our financial results are discussed in more detail on pages 48-49.

In 2008, nine major projects came onstream. Production commenced at the Thunder Horse field, with four wells in operation by the end of the year, producing around 200,000boe/d (gross) making us the largest producer in the Gulf of Mexico. We also started oil production on our Deepwater Gunashli platform in the Azerbaijan sector of the Caspian Sea. Other significant successes included the start of oil and gas production at the Saqqara and Taurt fields in Egypt. Production from our established centres including the North Sea, Alaska, North America Gas and Trinidad & Tobago, was on plan. We are also increasing our ability to get more from fields by improving our overall recovery rates through developing and applying new technology.

In terms of the continued renewal of our oil and natural gas resource base, 2008 was one of our best years this decade for new discoveries.

Total capital expenditure including acquisitions in 2008 was $22.2 billion (2007 $14.2 billion and 2006 $13.3 billion). In 2008, there were no significant acquisitions. Capital expenditure included $2.8 billion relating to the formation of an integrated North American oil sands business with Husky Energy Inc. It also included $3.7 billion relating to the purchase of all Chesapeake Energy Corporation s interest in the Woodford Shale assets in the Arkoma basin, and the purchase of a 25% interest in Chesapeake s Fayetteville Shale assets, enabling further growth of our North American gas business.

There were no significant acquisitions in 2006 and 2007. Capital expenditure in 2006 included our investment of $1 billion in Rosneft.

Development expenditure incurred in 2008, excluding midstream activities, was $11,767 million, compared with $10,153 million in 2007 and $9,109 million in 2006.

Looking ahead, our priorities remain the same: safety, people and performance. We will continue to strive to deliver safe, reliable and efficient operations while maintaining our flexibility so we can respond to oil price volatility.

In 2009, oil and gas prices are expected to be significantly lower than 2008. In response we will aim to use the operational momentum generated in 2008 to continue to increase the efficiency of our cost base and to build capability for the future. We intend to retain our rigour around capital investment, in particular pacing our development to take advantage of any cost reductions in a deflationary environment, and supporting our strategy of growing the upstream business. We believe that our portfolio of assets is strong and is well positioned to compete and grow in a range of external conditions.

Comparative information presented in the table on the following page has been restated, where appropriate, to reflect the resegmentation, following transfers of certain businesses between segments, that was effective from 1 January 2008. See page 12 for more details.

Performance review

Key statistics

			$ million
	2008	2007	2006
Total revenues[a]	**89,902**	69,376	71,868
Profit before interest and tax from continuing operations[b]	**37,915**	27,729	30,953
Total assets	**136,665**	125,736	124,803
Capital expenditure and acquisitions	**22,227**	14,207	13,252
			million barrels of oil equivalent
Net proved reserves group	**12,562**	12,583	13,163
Net proved reserves equity-accounted entities	**5,585**	5,231	4,537
			thousand barrels per day
Liquids production group	**1,263**	1,304	1,351
Liquids production equity-accounted entities	**1,138**	1,110	1,124
			million cubic feet per day
Natural gas production group	**7,277**	7,222	7,412
Natural gas production equity-accounted entities	**1,057**	921	1,005
			$ per barrel
Average BP crude oil realizations[c]	**95.43**	69.98	61.91
Average BP NGL realizations[c]	**52.30**	46.20	37.17
Average BP liquids realizations[c d]	**90.20**	67.45	59.23
Average West Texas Intermediate oil price	**100.06**	72.20	66.02
Average Brent oil price	**97.26**	72.39	65.14
			$ per thousand cubic feet
Average BP natural gas realizations[c]	**6.00**	4.53	4.72
Average BP US natural gas realizations[c]	**6.77**	5.43	5.74

	$ per million British thermal units		
Average Henry Hub gas price[e]	**9.04**	6.86	7.24
	pence per therm		
Average UK National Balancing Point gas price	**58.12**	29.95	42.19

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

[c]Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[d]Crude oil and natural gas liquids.
[e]Henry Hub First of Month Index.
Total revenues are analysed in more detail below.

			$ million
	2008	2007	2006
Sales and other operating revenues	**86,170**	65,740	67,950
Earnings from equity-accounted entities (after interest and tax), interest and other revenues	**3,732**	3,636	3,918
	89,902	69,376	71,868

Upstream activities
Exploration
The group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

Our exploration and appraisal costs, excluding lease acquisitions, in 2008 were $2,290 million, compared with $1,892 million in 2007 and $1,765 million in 2006. These costs include exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred. Approximately 51% of 2008 exploration and appraisal costs were directed towards appraisal activity. In 2008, we participated in 83 gross (34 net) exploration and appraisal wells in 11 countries. The principal areas of activity were Algeria, Angola, Azerbaijan, Canada, Egypt, the deepwater Gulf of Mexico, Libya, the North Sea and onshore US.

Total exploration expense in 2008 of $882 million (2007 $756 million and 2006 $1,045 million) included the write-off of expenses related to unsuccessful drilling activities in Azerbaijan ($105 million), Faeroes ($83 million), Egypt ($64 million), deepwater Gulf of Mexico ($38 million), and others ($33 million).

In 2008, we obtained upstream rights in several new tracts, which include the following:

In the Gulf of Mexico, we were awarded 125 blocks through the Outer Continental Shelf Lease Sales 205, 206 and 207.

In the US Lower 48 states, we acquired 225,000 net acres of shale gas assets from Chesapeake Energy Corporation.

In Canada, BP acquired three licences, covering a total of approximately 6,000 square kilometres in the Canadian Beaufort Sea.

In India, BP acquired one block on the East Coast in the New Exploration Licensing Policy seventh round.

In 2008, we were involved in a number of discoveries. In most cases, reserves bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our most significant discoveries in 2008 included the following:

In Angola, we made further discoveries in the ultra deepwater (greater than 1,500 metres) Block 31 (BP 26.7% and operator) with the Portia and Dione wells, bringing the total number of discoveries in Block 31 to 16.

In Algeria, we discovered natural gas in the Tin Zaouatene-1 well in the Bourarhet Sud Blocks 230 and 231 (BP 49% and operator).

In Egypt, we made a discovery with the Satis (BP 50% and operator) well.

In the UK, we made two discoveries with the South West Foinaven (BP 72% and operator) and the Kinnoull (BP 77% and operator) wells.

In the deepwater Gulf of Mexico, we made two discoveries with the Kodiak (BP 63.75% and operator) and Freedom (BP 25% and operator) wells.

Reserves and production

Compliance

IFRS does not provide specific guidance on reserves disclosures.

BP estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant guidance notes and letters issued by the SEC staff. As currently required, these proved reserve estimates are based on prices and costs as of the date the estimate is made.

On 31 December 2008, the SEC published a revised set of rules for the estimation of reserves. These revised rules will be used for the 2009 year-end estimation of reserves, and have not been used in the determination of reserves for year-end 2008.

By their nature, there is always some risk involved in the ultimate development and production of reserves, including, but not limited to, final regulatory approval, the installation of new or additional infrastructure as well as changes in oil and gas prices, changes in operating and development costs and the continued availability of additional development capital.

Performance review

All the group s oil and gas reserves held in consolidated companies have been estimated by the group s petroleum engineers. Of the equity-accounted volumes in 2008, 18% were based on estimates prepared by group petroleum engineers and 82% were based on estimates prepared by independent engineering consultants, although all of the group s oil and gas reserves held in equity-accounted entities are reviewed by the group s petroleum engineers before making the assessment of volumes to be booked by BP.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where title to the hydrocarbons is not conferred, such as production-sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. Sixteen per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSAs are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

We separately disclose our share of reserves held in equity-accounted entities (jointly controlled entities and associates), although we do not control these entities or the assets held by such entities.

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, non-proved resources and proved reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the non-proved resource category. The resources move through various non-proved resource sub-categories as their technical and commercial maturity increases through appraisal activity.

Resources in a field will only be categorized as proved reserves when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction or for sanction typically expected within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development, typically within three years. Where, on occasion, the group decides to book reserves where development is scheduled to commence after three years, these reserves will be booked only where they satisfy the SEC s criteria for attribution of proved status. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well s reserves depends on a later phase of activity, only that portion of reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking of PUD reserves to the start of production. Changes to reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.

Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group s business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.

Internal Audit, whose role includes systematically examining the effectiveness of the group s financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the group s compliance with laws, regulations and internal standards.

Approval hierarchy, whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews. The frequency of review is determined according to field size and ensures that more than 80% of the BP reserves base undergoes central review every two years and more than 90% is reviewed every four years.

For the executive directors and senior management, no specific portion of compensation bonuses is directly related to oil and natural gas reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Exploration and Production segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

BP s variable pay programme for the other senior managers in the Exploration and Production segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to oil and gas reserves.

Reserve replacement

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 12,562mmboe at 31 December 2008, a decrease of 0.2% compared with 31 December 2007. Natural gas represents about 55% of these reserves. The decrease includes a net decrease from acquisitions and divestments of 169mmboe, largely comprising a number of assets in Venezuela and the US.

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 5,585mmboe at 31 December 2008, an increase of 6.8% compared with 31 December 2007. Natural gas represents about 16% of these proved reserves. The increase includes a net increase from acquisitions and divestments of 199mmboe, largely comprising a number of assets in Venezuela. The proved reserves replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery and extensions and discoveries, and may be expressed as a replacement ratio excluding acquisitions and divestments or as a total replacement ratio including acquisitions and divestments.

BP estimates proved reserves for reporting purposes in accordance with SEC rules and relevant guidance. As currently required, these proved reserve estimates are based on prices and costs as of the date the estimate is made. There was a rapid and substantial decline in oil prices in the fourth quarter of 2008 that was not matched by a similar reduction in operating costs by the end of the year. BP does not expect that these economic conditions will continue. However, our 2008 reserves are calculated on the basis of operating activities that would be undertaken were year-end prices and costs to persist.

Performance review

			%
	2008	2007	2006
Proved reserves replacement ratio, excluding equity-accounted entities	**116**	44	34
Proved reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**98**	38	11
Proved reserves replacement ratio, for equity- accounted entities	**132**	248	272
Proved reserves replacement ratio, for equity- accounted entities, including sales and purchases of reserves-in-place	**172**	248	239
	million barrels of oil equivalent		
Additions to proved developed reserves, excluding equity-accounted entities, including sales and purchases of reserves-in-place[a]	**826**	929	675
Additions to proved developed reserves, for equity-accounted entities, including sales and purchases of reserves-in-place[a]	**751**	473	936
			%
Proved developed reserves replacement ratio, excluding equity-accounted entities, including sales and purchases of reserves-in-place	**88**	99	70
Proved developed reserves replacement ratio, for equity-accounted entities, including sales and purchases of reserves-in-place	**153**	101	195

[a]This includes some reserves that were previously classified as proved undeveloped.

In 2008, net additions to the group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 1,085mmboe, principally through improved recovery from, and extensions to, existing fields and discoveries of new fields. Of the reserves additions through improved recovery from, and extensions to, existing fields and discoveries of new fields, approximately half are associated with new projects and are proved undeveloped reserves additions. The remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped reserves. The principal reserves additions were in the US (Arkoma, Thunder Horse, Wamsutter), Trinidad (Mango), Asia-Pacific (Tangguh), Angola (Plutão, Saturno, Vênus and Marte, and Angola LNG) and Azerbaijan (ACG).

Production

Our total hydrocarbon production during 2008 averaged 2,517 thousand barrels of oil equivalent per day (mboe/d) for subsidiaries and 1,321mboe/d for equity-accounted entities, a decrease of 1.2% and an increase of 4.0% respectively compared with 2007. For subsidiaries, 36% of our production was in the US and 12% in the UK. For equity-accounted entities, 70% of production was from TNK-BP.

Total production is expected to be somewhat higher in 2009. The actual growth rate will depend on a number of factors, including our pace of capital spending, the efficiency of that spend (in turn depending on industry cost deflation), the oil price and its impact on PSAs as well as OPEC quota restrictions.

The following tables show BP s estimated net proved reserves as at 31 December 2008.

Estimated net proved reserves of liquids at 31 December 2008[a b c]

	Developed	Undeveloped	Total (million barrels)
UK	410	119	529
Rest of Europe	81	194	275
US	1,717	1,273	2,990[d]
Rest of Americas	58	56	114[e]
Asia Pacific	77	69	146
Africa	464	496	960
Russia			
Other	174	477	651
Group	2,981	2,684	5,665
Equity-accounted entities	3,125	1,563	4,688[f]

Estimated net proved reserves of natural gas at 31 December 2008[a b c]

	Developed	Undeveloped	Total (billion cubic feet)
UK	1,822	582	2,404
Rest of Europe	61	402	463
US	9,059	5,473	14,532
Rest of Americas	3,975	7,902	11,877[g]
Asia Pacific	2,482	4,275	6,757
Africa	1,050	1,382	2,432
Russia			
Other	507	1,033	1,540
Group	18,956	21,049	40,005
Equity-accounted entities	3,234	1,969	5,203[h]

Net proved reserves on an oil equivalent basis

	Developed	Undeveloped	Total (mmboe)
Group	6,249	6,313	12,562
Equity-accounted entities	3,683	1,902	5,585

[a]Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include minority interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b]In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological

improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. The general method of reserves assessment to determine reasonable certainty of commercial recovery which BP employs relies on the integration of three types of data: (1) well data used to assess the local characteristics and conditions of reservoirs and fluids; (2) field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control; and (3) data from relevant analogous fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing a better understanding of the overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. Historically, proved reserves recorded using these methods have been validated by actual production levels. As at the end of 2008, BP had proved reserves in 20 fields in the deepwater Gulf of Mexico that had been initially booked prior to production flow testing. Of these fields, 18 are in production and two, Dorado and Great White, are expected to begin production in 2009. Six other fields are in the early stages of appraisal and development.

[c]The 2008 year-end marker prices used

were Brent $36.55/bbl (2007 $96.02/bbl and 2006 $58.93/bbl) and Henry Hub $5.63/mmBtu (2007 $7.10/mmBtu and 2006 $5.52/mmBtu).

[d]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e]Includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[f]Includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.

[g]Includes 3,108 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[h]Includes 131 billion cubic feet of natural gas in respect of the 5.92% minority interest in TNK-BP.

Performance review

The following tables show BP s production by major field for 2008, 2007 and 2006.
Liquids

		%	thousand barrels per day		
			BP net share of production [a]		
	Field or Area	Interest	**2008**	2007	2006
Alaska	Prudhoe Bay[b]	26.4	**72**	74	71
	Kuparuk	Various	**48**	52	57
	Northstar[b]	98.6	**22**	28	38
	Milne Point[b]	Various	**27**	28	31
	Other	Various	**28**	27	27
Total Alaska			**197**	209	224
Lower 48 onshore[c]	Various	Various	**97**	108	125
Gulf of Mexico deepwater[c]	Na Kika[b]	Various	**29**	32	41
	Thunder Horse[b]	75.0	**24**		
	Horn Mountain[b]	100.0	**18**	18	23
	King[b]	100.0	**23**	22	28
	Mars	28.5	**28**	30	19
	Mad Dog[b]	60.5	**31**	25	17
	Atlantis[b]	56.0	**42**	2	
	Other	Various	**49**	67	70
Total Gulf of Mexico			**244**	196	198
Total US			**538**	513	547
UK offshore[c]	ETAP[d]	Various	**27**	32	49
	Foinaven[b]	Various	**26**	37	37
	Magnus[b]	85.0	**18**	16	30
	Schiehallion/Loyal[b]	Various	**18**	20	26
	Clair[b]	28.6	**13**	9	7
	Harding[b]	70.0	**11**	14	17
	Andrew[b]	62.8	**7**	8	7
	Other	Various	**37**	50	62
Total UK offshore			**157**	186	235
Onshore	Wytch Farm[b]	67.8	**16**	15	18
Total UK			**173**	201	253

Netherlands[c]	Various	Various			1
Norway	Valhall[b]	28.1	**14**	17	21
	Draugen	18.4	**13**	14	15
	Ula[b]	80.0	**8**	12	14
	Other	Various	**8**	8	10
Total Rest of Europe			**43**	51	61
Angola	Dalia	16.7	34	31	
	Girassol	16.7	**6**	14	17
	Greater Plutonio[b]	50.0	**69**	12	
	Kizomba A	26.7	**15**	36	54
	Kizomba B	26.7	**16**	35	58
	Other	Various	**62**	12	4
Australia	Various	15.8	**29**	34	34
Azerbaijan	Azeri-Chirag-Gunashli[b]	34.1	**97**	200	145
	Shah Deniz[b]	25.5	**8**	5	
Canada[c]	Various[b]	Various	**9**	**8**	8
Colombia	Various[b]	Various	**24**	28	34
Egypt	Various	Various	**57**	43	42
Trinidad & Tobago	Various[b]	100.0	**37**	30	40
Venezuela[c]	Various	Various	**4**	16	26
Other[c]	Various	Various	**42**	35	28
Total Rest of World			**509**	539	490
Total group[e]			**1,263**	1,304	1,351
Equity-accounted entities (BP share)					
Abu Dhabi[f]	Various	Various	**210**	192	163
Argentina Pan American Energy	Various	Various	**70**	69	69
Russia TNK-BP[c]	Various	Various	**826**	832	876
Other[c]	Various	Various	**32**	17	16
Total equity-accounted entities			**1,138**	1,110	1,124

[a]Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements

independently.

[b]BP-operated.

[c]In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position and TNK-BP disposed of some non-core interests. In 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core

interests in the Udmurtneft assets.

[d]Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

[e]Includes 19 net mboe/d of NGLs from processing plants in which BP has an interest (2007 54mboe/d and 2006 55mboe/d).

[f]The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes.

Performance review

Natural gas

		%	million cubic feet per day		
			BP net share of production[a]		
	Field or Area	Interest	**2008**	2007	2006
Lower 48 onshore[b]	San Juan[c]	Various	**682**	694	765
	Arkoma[c]	Various	**240**	204	225
	Hugoton[c]	Various	**91**	123	137
	Tuscaloosa[c]	Various	**65**	78	86
	Wamsutter[c]	66.6	**136**	120	113
	Jonah[c]	Various	**221**	173	133
	Other	Various	**451**	458	461
Total Lower 48 onshore			**1,886**	1,850	1,920
Gulf of Mexico deepwater[b]	Na Kika[c]	51.9	**62**	50	97
	Marlin[c]	78.2	**46**	13	16
	Other	Various	**122**	205	210
Gulf of Mexico Shelf[b]	Other	Various		1	66
Total Gulf of Mexico			**230**	269	389
Alaska	Various	Various	**41**	55	67
Total US			**2,157**	2,174	2,376
UK offshore[b]	Braes	Various	**75**	69	101
	Bruce[c]	37.0	**65**	72	107
	West Sole[c]	100.0	**51**	55	56
	Marnock[c]	62.1	**24**	25	42
	Britannia	9.0	**30**	37	42
	Shearwater	27.5	**17**	19	31
	Armada	18.2	**16**	16	28
	Other	Various	**481**	475	529
Total UK			**759**	768	936
Netherlands[b]	P/18-2	48.7			23
	Other	Various		3	33
Norway	Various	Various	**23**	26	35
Total Rest of Europe			**23**	29	91

Australia	Various	15.8	**380**	376	364
Canada[b]	Various[c]	Various	**245**	255	282
China	Yacheng[c]	34.3	**91**	85	102
Egypt	Ha'py[c]	50.0	**94**	108	99
	Other	Various	**278**	206	172
Indonesia	Sanga-Sanga (direct)[c]	26.3	**69**	75	84
	Other[c]	46.0	**98**	81	80
Sharjah	Sajaa[c]	40.0	**65**	83	111
	Other	40.0	**8**	9	9
Azerbaijan	Shah Deniz[c]	25.5	**143**	73	
Trinidad & Tobago	Kapok[c]	100.0	**619**	984	946
	Mahogany[c]	100.0	**323**	454	321
	Amherstia[c]	100.0	**288**	155	176
	Parang[c]	100.0			120
	Immortelle[c]	100.0	**136**	153	219
	Cassia[c]	100.0	**5**	25	30
	Other[c]	100.0	**1,075**	663	453
Other[b]	Various	Various	**421**	466	441
Total Rest of World			**4,338**	4,251	4,009
Total group[d]			**7,277**	7,222	7,412
Equity-accounted entities (BP share)					
Argentina Pan American Energy	Various	Various	**385**	379	362
Russia TNK-BP[b]	Various	Various	**564**	451	544
Other[b]	Various	Various	**108**	91	99
Total equity-accounted entities[d]			**1,057**	921	1,005

[a]Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with PDVSA while retaining its equity position. In 2007, BP divested its producing properties in the Netherlands and some producing properties in the US Lower 48 and Canada. TNK-BP disposed of its interests in several non-core properties. In 2006, BP divested its producing properties on the Outer Continental Shelf of the Gulf of Mexico and its interest in the Statfjord oil and gas field in the UK. Our interests in the Boqueron, Desarollo Zulia Occidental (DZO) and Jusepin projects in Venezuela were reduced following a decision by the Venezuelan government. TNK-BP disposed of its non-core interests in the Udmurtneft assets.

[c]BP-operated.

[d]Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group s reserves.

Performance review

United States
2008 liquids production at 538mb/d increased 4.9% from 2007, while natural gas production at 2,157mmcf/d decreased 0.8% compared with 2007.

Crude oil production increased by 32mb/d, an increase of 8% from 2007, primarily driven by major projects in the Gulf of Mexico, partly offset by natural reservoir decline and the impact of hurricanes in the third quarter.

The NGLs component of liquids production decreased by 7mb/d, driven mainly by plant turnarounds and operational issues resulting from the hurricanes in the third quarter. BP operates or has interests in NGL extraction plants with a processing capacity of 6.4bcf/d. These facilities are located in major production areas across North America, including Alberta, Canada, the US Rockies, the San Juan basin and the Gulf of Mexico. We also own or have an interest in fractionation plants (that separate the NGL into its component products) in Canada and the US.

Gas production was 17mmcf/d lower because of natural reservoir decline and the impact of hurricanes, which was partly offset by production from shale acquisitions.

Development expenditure in the US (excluding midstream) during 2008 was $4,914 million, compared with $3,861 million in 2007 and $3,579 million in 2006. The year-on-year increase is the result of various development projects in progress.

Our activities within the US take place in three main areas: deepwater Gulf of Mexico, the Lower 48 states and Alaska. Significant events during 2008 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is our largest area of growth in the US. In 2008, our deepwater Gulf of Mexico liquids production was 244mb/d and gas production was 40mboe/d

Significant events were:

On 14 June 2008, first oil was achieved at Thunder Horse (BP 75% and operator). Thunder Horse is the world s largest semi-submersible production facility, and is located 150 miles south-east of New Orleans. It is designed to process 250,000 barrels of oil per day and 200 million cubic feet per day of natural gas. In 2008 four wells started up with production of around 200,000boe/d (gross) at the year-end, signalling the completion of commissioning. Production started up in the Thunder Horse North field in February 2009.

On 3 April 2008, BP announced an oil discovery at its Kodiak prospect (BP 63.75% and operator). The well, located in Mississippi Canyon block 771, approximately 60 miles south-east of the Louisiana Coast, is in about 1,500 metres of water.

In September 2008, Hurricanes Gustav and Ike resulted in most of the Gulf of Mexico s oil production being shut down. There was minimal damage to most of BP s platforms other than to the drilling derrick on the Mad Dog platform, located approximately 190 miles south of New Orleans. The production impact of both hurricanes was a reduction equivalent to approximately 24mboe/d for the year.

In October 2008, BP announced an oil discovery with its Freedom well (BP 25% and operator). The well, located in Mississippi Canyon Block 948, approximately 70 miles south-east of the Louisiana Coast, is in about 1,860 metres of water. It is believed that Freedom straddles Mississippi Canyon Block 948 and Mississippi Canyon Block 992. BP owns a 67.75% interest in Block 992.

Lower 48 states

In the Lower 48 states (onshore), our 2008 natural gas production was 325mboe/d, which was up 2% compared with 2007. Liquids production was 97mb/d, down 10% compared with 2007. Total 2008 production, excluding the impacts from the 2008 hurricanes, was broadly flat compared with 2007.

In 2008, we drilled approximately 540 wells as operator and continued to maintain a stable programme of drilling activity throughout the year.

Production is derived from two main areas:

In the western basins (Colorado, New Mexico and Wyoming), our assets produced 224mboe/d in 2008.

In the Gulf Coast and mid-continental basins (Kansas, Louisiana, Oklahoma and Texas), our assets produced 198mboe/d in 2008.

Significant events were:

In August 2008, BP acquired all Chesapeake Energy Corporation s interest in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma basin Woodford Shale area for $1.75 billion. BP took over production operations on 1 November and retained three drilling rigs as part of the deal.

In September 2008, BP acquired a 25% non-operated interest in Chesapeake s Fayetteville Shale assets for $1.9 billion comprising $1.1 billion in cash at closing and an $800 million commitment to fund Chesapeake s 75% share of drilling and completion costs. $183 million of this commitment was met in 2008, with the balance expected to be paid by the end of 2009. The assets include approximately 135,000 net acres of leasehold.

In September 2008, in anticipation of Hurricane Gustav, operations and activity were shut down in the Pascagoula NGL plant, South Louisiana (Tuscaloosa field) and East Texas Exploration and Production operations. Also in September, Hurricane Ike resulted in every field location across South Louisiana, East Texas and the Permian Basin having production shut in. Four NGL plants, Pascagoula, Block 31, Crane and Midland, were shut down while other plants suffered production impacts due to widespread outages and disruptions in the midstream infrastructure. The impact of both hurricanes on production was a reduction equivalent to approximately 2mboe/d for the year.

In October 2008, BP sanctioned the Wamsutter Full Field Development plan (Phase ll). This builds on the operational and technological results of extensive field trials conducted during the past three years.

Alaska

In Alaska, BP net oil production in 2008 was 197mb/d, a decrease of 6% from 2007, due to normal decline in the large mature fields, partially offset by continued strong reservoir and well performance.

BP operates 13 North Slope oil fields (including Prudhoe Bay, Northstar and Milne Point) and four North Slope pipelines and owns a significant interest in six other producing fields

In addition, two key aspects of BP s business strategy in Alaska are commercializing the large undeveloped natural gas resource within our 26.4% interest in Prudhoe Bay and unlocking the large undeveloped heavy oil resources within existing North Slope fields through the application of advanced technology.

Significant events in 2008 were:

In July 2008, BP announced the commencement of development activities for the Liberty oilfield, which is located on federal leases about six miles offshore in the Beaufort Sea, and east of the Prudhoe Bay oilfield. The planned development includes up to six ultra-extended reach wells, including four producers and two injectors. These wells are expected to be the longest horizontal wells ever drilled in the world, extending two miles deep and as far as eight miles horizontally, guided by 3-D seismic imagery. A specialized rig for drilling in the Arctic is being built for the project. Drilling is expected to start in 2010, from an existing satellite pad that is being expanded for

Performance review

the project at the BP-operated Endicott oilfield. BP drilled the Liberty discovery well in 1997, and is the operator and sole owner of the field.

In August 2008, BP successfully tested Cold Heavy Oil Production with Sand (CHOPS) technology for the first time in Alaska, initiating a four-well production test programme during the period from August 2008 until the end of 2009. This first test at Milne Point S Pad brought oil and sand to the surface, where it was processed using temporary field facilities, combined with other light oil production, and shipped down the Trans-Alaska Pipeline System (TAPS). The CHOPS well tests are part of a multi-year programme to determine the technical and commercial feasibility of a large scale heavy oil development project on the North Slope using existing cold and thermal technologies.

During 2008, all four of the Prudhoe Bay Oil Transit Line segments that were targeted for replacement in response to the oil spills in the Prudhoe Bay field in March and August 2006 were completed and placed in service.

United Kingdom

We are the largest producer of oil, the second largest producer of gas and the largest overall producer of hydrocarbons in the UK. In 2008, total liquids production was 173mb/d, a 14% decrease on 2007, and gas production was 759mmcf/d, a 1% decrease on 2007. This decrease in production was driven by natural decline. Key aspects of our activities in the North Sea include a focus on in-field drilling and selected new field developments. Our development expenditure (excluding midstream) in the UK was $907 million in 2008, compared with $804 million in 2007 and $794 million in 2006. BP operates one NGL plant in the UK.

Significant events in 2008 were:

In February 2008, BP and its partner, Marathon Petroleum West of Shetlands Ltd, announced a new oil discovery in UK Continental Shelf Block 204/23 (BP 72%), following drilling on the South West Foinaven prospect. BP, together with its partner, is evaluating the discovery and the potential for a two-well subsea development, tied back to the Foinaven Floating Production Storage and Offloading vessel (FPSO).

In May 2008, BP and its co-venturers made an oil discovery in North Sea Block 16/23s (BP 77.07%), named Kinnoull. The Kinnoull discovery and potential development options, including a subsea development tied back to BP s Andrew field, are being evaluated.

During the third quarter, the first phase of offshore removal activity for the North West Hutton platform decommissioning programme was completed. This is BP s biggest decommissioning project so far in the North Sea and has seen the removal of 22 separate topsides modules, which were then taken away by barges to the Able UK yard on Teesside for recycling and disposal. It is estimated that around 97% of the material recovered will be recycled and/or reused.

In December 2008, BP and BG Group agreed to exchange a package of North Sea assets. This is expected to strengthen BP s position as a major operator in the Southern North Sea and to facilitate development activity and investment in the UK Continental Shelf. BP agreed to acquire BG s 24.2% interest in the BP-operated Amethyst field and all its interests in the Easington Catchment Area (ECA) fields, including a 73.3% interest in the Mercury field, a 79% interest in the Neptune field, a 65% interest in the Minerva, Apollo and Artemis fields and BG s 30.8% interest in the BP-operated Whittle and Wollaston fields. BG Group agreed to acquire BP s interest and operatorship in the Everest (BP 21.1%) and Lomond (BP 22.2%) fields, BP s 18.2% interest in the BG-operated Armada field and 32% of the Chevron-operated Erskine field (BP will retain 18% equity in Erskine). The deal is subject to government, regulatory and partner approvals and completion is expected in the second quarter of 2009.

Rest of Europe

Our activities in the Rest of Europe are now centred on Norway. Until February 2007, we also held exploration and production and gas infrastructure interests in the Netherlands. Development expenditure (excluding midstream) in the Rest of Europe was $695 million, compared with $443 million in 2007 and $214 million in 2006. In 2008, our total production in Norway was 47mboe/d, a 16% decrease on 2007. This decrease in production was driven by natural decline. In Norway, progress continued as planned on the Skarv and Valhall Redevelopment projects.

Rest of World

Development expenditure in Rest of World (excluding midstream) was $5,251 million in 2008, compared with $5,045 million in 2007 and $4,522 million in 2006.

Rest of Americas

Canada

In Canada, our natural gas and liquids production was 51mboe/d in 2008, a decrease of 1% compared with 2007. The year-on-year decrease in production is mainly due to natural field decline.

On 31 March 2008, BP and Husky Energy Inc. (Husky) completed a deal to create an integrated North American oil sands business by means of two separate 50:50 joint ventures, BP-Husky Refinery LLC, operated by BP, and the Sunrise Oil Sands Partnership (SOSP), operated by Husky. BP s capital expenditure in respect of the creation of SOSP amounted to $2.8 billion.

In June 2008, BP successfully acquired three of five exploration licences on offer in the Canadian section of the Beaufort Sea through a Call for Bids process issued by The Department of Indian and Northern Affairs of Canada. The leases awarded to BP cover about 611,000 hectares of the Beaufort seabed, north of Tuktoyaktuk, Northwest Territories. These are in addition to the 15 significant discovery licences that BP currently holds in the Beaufort Sea, and two exploration licences currently in moratorium. The term for exploration licences issued from this Call for Bids is nine years consisting of two consecutive periods. There is a $300 million work obligation associated with acquiring these exploration licences.

Trinidad

In Trinidad, natural gas production volumes increased from 420mboe/d in 2007 to 422mboe/d in 2008. The increase was a result of improved operating efficiency on the Atlantic LNG Trains combined with increased demand from the domestic market and full ramp-up of two new fields, Mango and Cashima. Liquids production increased by 7mb/d (23%) to 37mb/d in 2008 from 30mb/d in 2007 as a result of an increase in NGLs associated with higher throughput for the Trains, increased crude and condensate from the two new fields and liquid optimization activities.

In December 2008, a new oil export pipeline was commissioned to transport liquids from offshore fields to onshore delivery points. BP owns 100% of the capacity of the pipeline.

Progress on Savonette, BP s next field development in Trinidad, continued throughout the year and first gas is expected to be delivered in 2009.

In 2008, the Day Away from Work Case injury frequency (per 200,000 work hours) has been reduced from 0.12 in 2003 to zero in 2008 and the recordable injury frequency has more than halved in the same period. This has come about through the development and implementation of a comprehensive multi-year safety plan, focused on coaching safety leaders, workforce communication, standard implementation and continuous learning.

Performance review

Venezuela

In Venezuela, despite the transition since 2006 of BP s interests to incorporated joint venture (IJV) entities with the state oil company Petróleos de Venezuela, S.A. (PDVSA), and OPEC quotas, 2008 liquids production increased by 3mb/d compared with 2007.

In the second quarter of 2008, BP concluded the migration of the Cerro Negro operations to an IJV with PDVSA while retaining the same equity interest.

Colombia

In Colombia, BP s net production averaged 38mboe/d. The reduction of 8mboe/d compared with 2007 is mainly due to natural field decline and lower gas transfers from Recetor (BP 50%) to Santiago de las Atalayas (BP 31%). The main part of the production comes from the Cusiana, Cupiagua and Cupiagua South fields, with increasing new production from the Cupiagua extension into the Recetor Association Contract and the Floreña and Pauto fields in the Piedemonte Association Contract.

On 20 June 2008, the National Hydrocarbon Agency gave its official approval for equalization of RC4 and RC5 Caribbean offshore blocks with partners Ecopetrol and Petrobras, with the main objective of simplifying partner relations and agreements. New equity interests resulting from this approval are BP 40.6%, Ecopetrol 32% and Petrobras 27.4%. Seismic operations for these two blocks were completed successfully. Processing and interpretation of the data to determine potential prospects for offshore field developments and drilling operations is under way and is expected to be completed in 2009.

Argentina, Bolivia and Chile

In Argentina, Bolivia and Chile, activity is conducted through Pan American Energy (PAE), a joint venture company in which BP holds a 60% interest, and which is accounted for by the equity method. In 2008, total PAE gross production of 250mboe/d represented an increase of 3% compared with 2007. Most of this production comes from the Cerro Dragón field in the provinces of Chubut and Santa Cruz. The field is now producing at its highest level since inception of the licence area in 1958. PAE also has other assets producing gas and liquids in the Argentine provinces of Salta, Neuguén and Tierra del Fuego, and in Bolivia, as well as interests in exploration areas, pipelines, electricity generation plants and other midstream infrastructure assets, primarily in Argentina.

In 2007 and early 2008, PAE was granted extensions of the two principal Cerro Dragón licence areas by the provinces of Chubut and Santa Cruz in exchange for material long-term investment commitments in exploration and production, and for long-term commitments to local community and supplier development. The licence expiry dates have been extended from 2017 to 2027, with further extension potential to 2047.

In May 2008, following its decree of 2006 requiring all private owners of shares in Bolivian oil and gas companies to transfer back a majority shareholding to the Bolivian national oil company Yacimientos Petrolíferos Fiscales Bolivianos (YPFB), the Bolivian government issued a second decree requiring this transfer to be made with immediate effect. PAE, as the majority shareholder of Empresa Petrolera Chaco S.A. (Chaco), a company created in the 1990s, was affected by these decrees. PAE was required to sell approximately 1% of the share capital of Chaco to YPFB, such that YPFB would own 50% plus one share of the total. From May 2008 and into January 2009, PAE was in discussions with the government regarding the decrees and options for implementation. However, on 23 January 2009, the president of Bolivia issued a decree nationalizing PAE s shareholding in Chaco. PAE is currently evaluating all options to preserve the value of its shareholding.

On 26 November 2008, the Argentine government issued a decree creating a new regime called Petróleo PLUS. This regime is aimed at increasing oil production and reserves. The detailed rules of Petróleo PLUS were issued on 4 December 2008. On 15 December 2008, PAE made its first applications under Petróleo PLUS for fiscal credit certificates with the Secretary of Energy.

Africa

Algeria

BP, through its joint operatorships of the In Salah Gas (33.15%) and In Amenas (12.5%) projects, supplied 33mboe/d (BP net) to markets in Algeria and southern Europe during 2008. This is a decrease of 15% from 39mboe/d in 2007 as a result of lower gross volumes at In Salah due to planned turnaround maintenance and the impact of lower entitlement in our PSAs driven by higher prices, partly offset by improved operating efficiency at In Amenas. Further, BP, through its joint operatorship of the Rhourde El Baguel field, received 4.4mboe/d (BP net) of oil in 2008.

Sonatrach and BP announced an exploration success with the Tin Zaouatene-1 (TZN-1) discovery in the Bourarhet Sud Blocks 230 and 231. On 24 September 2008, BP moved into the second prospecting period, which lasts for a further two years.

Angola

In Angola, BP net production in 2008 was 202mboe/d, an increase of 45% from 2007 due to the start-up of the Mondo, Saxi and Batuque (Kizomba C, BP 26.67%) fields, and the ramp-up of the Greater Plutonio field (BP 50% and operator), more than offsetting the impact of lower entitlement in our PSAs driven by higher prices in existing fields. We expect to have invested over $15 billion in our Angolan business by 2010.

In January 2008, the Kizomba C project (BP 26.67%) came onstream with the start-up of the Mondo field, followed by first production from the Saxi and Batuque fields in July 2008. The Kizomba C development is located approximately 140 kilometres off the coast of Angola in water depths of nearly 800 metres.

In June 2008, the Plutão, Saturno, Vênus and Marte (PSVM) project was authorized by Sonangol. The programme is expected to comprise four fields that lie in the north east sector of Block 31 (BP 26.67% and operator), in a water depth of approximately 2,000 metres, some 400 kilometres north west of Luanda. Contracts have been awarded and construction work started during 2008.

During the third quarter of 2008, production was shut down at the Greater Plutonio FPSO located in deepwater Block 18 (BP 50% and operator), offshore Angola, due to operational issues. Production was restarted on 12 October 2008. The adverse impact on full-year production was 14mb/d.

In the ultra deepwater Block 31 (BP 26.67% and operator), there was further exploration success with the Portia and Dione wells, bringing the total successes for Block 31 to 16. The Portia well is located in a water depth of approximately 2,000 metres, some 386 kilometres north-west of Luanda. The Dione well is located in a water depth of approximately 1,700 metres, some 390 kilometres north-west of Luanda.

Performance review

Egypt

In Egypt, BP net production was 121mboe/d, an increase of 25% from 97mboe/d in 2007. This increase was mainly due to the start-up of two new fields, Saqqara and Taurt, and the full-year impact from Denise, which started up at the end of 2007.

In January 2008, BP completed drilling a successful exploration well, Satis-1, in the North El Burg offshore concession (BP 50% and operator). The Satis-1 well was drilled in approximately 90 metres of water, some 50 kilometres offshore, and is in the Oligocene formation.

In January 2008, an oil discovery was announced in the North Shadwan (BP 50% and operator) concession located in the southern part of the Gulf of Suez. The NS394-1A exploration well was drilled in shallow water seven kilometres from the Hilal field. This discovery is the first new oil discovery in the south-eastern area of the Gulf of Suez in more than 10 years and is also the first discovery drilled by BP which has been facilitated by modern, high-quality, ocean-bottom cable (OBC) seismic data.

On 15 May 2008, oil production from the Saqqara field (BP 100%) started. The Saqqara field, operated by the Gulf of Suez Petroleum Company (GUPCO), a joint venture operating company between BP and the Eygptian General Petroleum Corporation (EGPC), is located 13 kilometres offshore in the central Gulf of Suez. Natural gas production commenced on 26 July 2008. The Saqqara development includes a jacket and unmanned topsides, three wells, and a 13-kilometre pipeline to a new dedicated onshore separation and gas processing plant at Ras Shukeir on the Gulf of Suez. Local contractors were used for design, onshore construction and offshore fabrication work.

In July 2008, natural gas production began from the Taurt field (BP 50%). The Taurt field is located between the Ras El Bar Concession (BP 50% and operator) and the Temsah Concession (BP 50%), 70 kilometres offshore to the north-east of Port Said, East Nile Delta. Gross Taurt production ramped up to 230mmcf/d in August. The Taurt development includes a Subsea Production System (SPS), two subsea wells, and a 70-kilometre pipeline and control umbilical back to upgraded facilities at the existing West Harbor processing plant. Taurt is BP s first subsea development in Egypt and also the first of a planned programme of future subsea developments. Local contractors were used for onshore design/modifications and subsea structure construction.

Libya

In Libya, BP and its partner, the Libyan Investment Corporation (LIC) commenced seismic operations on the acreage covered under the exploration and production-sharing agreement ratified in December 2007. In September 2008, the offshore seismic acquisition survey commenced in the Mediterranean waters of Libya s Gulf of Sirt. At the end of 2008, the onshore seismic operations commenced in the northern Ghadames block.

Asia Pacific

Indonesia

BP produces crude oil in, and supplies natural gas to, the island of Java through its holding in the Offshore Northwest Java PSA (BP 46%). In 2008, BP net production was 22mboe/d, an increase of 18% from 18.6mboe/d in 2007 as a result of improved operating efficiencies and increased gas demand in Java.

BP is operator of the Tangguh LNG project (BP 37.2%), which includes offshore platforms, pipelines and an LNG plant with two production trains with a total capacity of 7.6 million tonnes per annum (mtpa). In May 2008, gas was introduced from one of the two offshore platforms into the Onshore Receiving Facility (ORF). First commercial delivery of LNG is expected in the second quarter of 2009.

BP has a 50% interest in Virginia Indonesia Company LLC (Vico), the operator of the Sanga-Sanga PSA (BP 38%) supplying feedgas to Indonesia s largest LNG export facility, the Bontang LNG plant in Kalimantan.

Vietnam

BP participates in one of the country s largest foreign investment projects, the Nam Con Son gas project. This is an integrated resource and infrastructure project, which includes offshore gas production, a pipeline transportation system and a power plant. At midnight on 31 December 2007, the operation of the Nam Con Son Pipeline (BP 32.67%) transferred from BP to PetroVietnam (PVN). In September 2008, capacity of the Nam Con Son Pipeline was increased by 30% to allow for additional current and future expected volumes.

In 2008, BP net natural gas production was 61mmcf/d, a decrease of 26% from 82mmcf/d in 2007, primarily due to lower PSA entitlements. Gas sales from Block 6.1 (BP 35% and operator) are made under a long-term agreement for electricity generation at the Phu My 3 power plant (BP 33.3%).

BP has determined that its licences in Blocks 5.2 (BP 55.9% and operator) and 5.3 (BP 75% and operator) do not fit within its current portfolio and has decided to withdraw from them. BP is currently in active discussions with PVN, the Vietnamese government and joint venture partners to progress this withdrawal.

China

In 2008, natural gas production was 91mmcf/d BP net, an increase of 7% compared with 2007. This increase was mainly due to increased gas demand. A new development project was sanctioned in late 2008 to help meet the expected increase in demand in 2010 and beyond.

The Yacheng offshore gas field (BP 34.3%) supplies Castle Peak Power Company with feedgas for up to 70% of Hong Kong s gas-fired electricity generation. Additional gas is also sold to the Fuel & Chemical Company of Hainan.

In March 2007, the National People s Congress reduced the rate of corporation tax from 33% to 25% with effect from 1 January 2008.

Australia

BP is one of seven partners in the North West Shelf (NWS) venture. Six partners (including BP) hold an equal 16.67% interest in the infrastructure and oil reserves and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32% of gas and condensate reserves. The NWS venture is currently the principal supplier to the domestic market in Western Australia and one of the largest LNG export projects in Asia with five LNG Trains in operation.

In 2008, BP net gas production was 380mmcf/d, an increase of 1% from 2007 primarily due to increased domestic gas demand in Western Australia and the startup of NWS Train 5 and the Angel platform in the third quarter. BP net liquids production was 29mb/d, a decrease of 15% from 2007 due to natural field decline.

In March 2008, the North Rankin 2 (NR2) project was sanctioned. This links a second platform via a 100-metre bridge to the existing North Rankin A (NRA) platform. On completion, NRA and NR2 platforms are expected to be operated as a single integrated facility and to recover low pressure gas from the North Rankin and Perseus gas fields.

In September 2008, a fifth LNG train was successfully completed and commenced production at the Karratha gas plant. Train 5 increases NWS total annual production capacity from 11.9 to 16.3 million tonnes.

The Angel platform (BP 16.67%) was successfully commissioned and started producing gas during October 2008. Angel has a gross production capacity of 800 million standard cubic feet of raw gas and up to 50,000 barrels of condensate per day.

Performance review

Russia

TNK-BP

TNK-BP, a joint venture between BP (50%) and Alfa Group and Access-Renova (AAR) (50%), is an integrated oil company operating in Russia and the Ukraine. The TNK-BP group s major assets are held in OAO TNK-BP Holding. Other assets include the BP-branded retail sites in Moscow and the Moscow region and interests in OAO Rusia Petroleum and the OAO Slavneft group. The workforce comprises more than 60,000 people.

BP s investment in TNK-BP is held by the Exploration and Production segment and the results of TNK-BP are accounted for under the equity method in this segment.

TNK-BP has proved reserves of 7.1 billion barrels of oil equivalent (including its 49.9% equity share of Slavneft), of which 5 billion are developed. In 2008, TNK-BP s average liquids production was 1.65mmb/d, a decrease of just under 1% compared with 2007. The production base is largely centred in West Siberia (Samotlor, Nyagan and Megion), which contributes about 1.2mmboe/d, together with Volga Urals (Orenburg) contributing some 0.4mmboe/d. About 40% of total oil production is currently exported as crude oil and 20% as refined product.

Downstream, TNK-BP has interests in six refineries in Russia and the Ukraine (including Ryazan and Lisichansk and Slavneft s Yaroslavl refinery), with throughput of approximately 34 million tonnes per year. During 2008, TNK-BP purchased additional retail and other downstream assets in Russia and the Ukraine from a number of small companies. TNK-BP supplies approximately 1,400 branded filling stations in Russia and the Ukraine and, with the additional sites, is expected to have more than 20% market share of the Moscow retail market.

On 9 January 2009, BP reached final agreement on amendments to the shareholder agreement with its Russian partners in TNK-BP. The revised agreement is aimed at improving the balance of interests between the company s 50:50 owners, BP and Alfa Access-Renova (AAR), and focusing the business more explicitly on value growth.

The former evenly-balanced main board structure has been replaced by one with four representatives each from BP and AAR, plus three independent directors. Unanimous board support is required for certain matters including substantial acquisitions, divestments and contracts, and projects outside the business plan, together with approval of key changes to the TNK-BP group s financial framework and of related party transactions. A number of other matters will be decided by approval of a majority of the board, so that the independent directors will have the ability to decide in the event of disagreement between the shareholder representatives on the board. BP will continue to nominate the chief executive, subject to main board approval, and AAR will continue to appoint the chairman. The three independent directors appointed to the restructured main board are Gerhard Schroeder, former chancellor of the Federal Republic of Germany, James Leng, former chairman of Corus Steel and Alexander Shokhin, president of the Russian Union of Industrialists and Entrepreneurs. In addition, significant TNK-BP subsidiaries will have directors appointed by BP and AAR on their boards. Our investment in TNK-BP will be reclassified from a jointly controlled entity to an associate with effect from 9 January 2009.

The parties have confirmed their agreement to a potential future sale of up to 20% of a subsidiary of TNK-BP through an initial public offering (IPO) at an appropriate future point, subject to certain conditions and the consent of the Russian authorities.

In 2007, BP and TNK-BP signed heads of terms to create strategic business alliances with OAO Gazprom. Under the terms of this agreement, TNK-BP agreed to sell to Gazprom its stake in OAO Rusia Petroleum, the company that owns the licence for the Kovykta gas condensate field in East Siberia and its interest in East Siberia Gas Company. Discussions to conclude this disposal continue.

Sakhalin

BP and its Russian partner Rosneft agreed two Shareholder and Operating Agreements (SOAs) on 28 April 2008, recognizing BP as a 49% equity interest holder with Rosneft holding the remaining 51% interest in the two newly formed joint venture companies, Vostok Shmidt Neftegaz and Zapad Shmidt Neftegaz. BP also continues to hold a 49% equity interest in its third joint venture company at Sakhalin, Elvary Neftegaz, with Rosneft holding the remaining 51%. During the year, each of the three joint ventures held Geological and Geophysical Studies licences with the Russian Ministry of Natural Resources (MNR) to perform exploration seismic and drilling operations in these licence areas off the east coast of Russia. To date, 3D seismic data has been acquired in relation to all three licences. In the Elvary Neftegaz licence additional commitment 2D seismic data was acquired during 2008 in preparation for future drilling commitments. Exploration wells have been drilled in the Zapad-Shmidt Neftegaz and Elvary Neftegaz licences. In 2008, it was agreed by both shareholders to allow the Zapad-Shmidt Neftegaz licence to lapse at the end of its normal term.

Other

Azerbaijan

In Azerbaijan, BP s net production in 2008 was 130mboe/d, a net decrease of 40% from 2007. The primary elements of this were the effects of significantly higher prices resulting in a change in profit oil entitlement in line with the terms of the PSA and reduced cost oil entitlement, partially offset by an increase following the start-up of the Deepwater Gunashli (DWG) platform, the ramping up of three Azeri oil-producing platforms and the Shah Deniz condensate gas platform commencing production in 2007.

The DWG platform complex successfully started oil production on schedule on 20 April 2008. DWG completes the third phase of development of the Azeri-Chirag-Gunashli (ACG) field (BP 34.1% and operator) in the Azerbaijan sector of the Caspian Sea. The DWG complex is located in a water depth of 175 metres on the east side of the Gunashli field. The complex comprises two platforms a drilling and production platform linked by a bridge to a water injection and gas compression platform.

On 17 September 2008, a subsurface gas release occurred below the Central Azeri platform. As a precautionary measure, all personnel on the platform were safely transferred onshore. The Central Azeri platform was shut down until 19 December 2008, when following comprehensive investigation and recovery work, BP began to resume oil and gas production. Central Azeri processes oil and gas from West Azeri, and West Azeri was also temporarily shut down and then restored to normal operations on 9 October 2008. Operations of the Compressor and Water Injection Platform (CWP), which is linked by a bridge to Central Azeri, and the provision of power and injection water across three Azeri field platforms were re-established on 12 October 2008.

Middle East and South Asia

Production in the Middle East consists principally of the production entitlement of associates in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions respectively. In 2008, BP s share of production in Abu Dhabi was 210mb/d, up 9% from 2007 as a result of higher overall OPEC demand despite cuts implemented in the fourth quarter of 2008.

In July 2008, BP Sharjah signed a farm-out agreement with RAK Petroleum for the East Sajaa concession. Drilling of the first exploration well is expected in 2009.

In Block 61 in Oman, the challenges posed by the world s largest onshore azimuth 3D seismic survey led the BP Oman team to use a ground-breaking new technique known as Distance Separated Simultaneous Sweeping (DS3). This technique allows the acquisition

Performance review

in a single day of as much seismic data as previously obtained in a week. The invention of DS3 along with some other innovations allowed an efficient and cost effective survey of the Block to be completed within a six-month period. The first appraisal well was spudded in September 2008.

In Pakistan, BP s net oil production in 2008 was 8.2mboe/d, an increase of 30% from 2007, and BP s net gas production was 28.2mboe/d, an increase of 34% from 2007 as a result of the full-year impact of BP increasing its equity in the onshore Badin asset in 2007 to 84%.

In Pakistan, BP received an 18-month extension until January 2010 in Phase 1 of the initial term of Exploration Licences in respect of the offshore Indus PSA.

On 30 December 2008, BP signed completion documents with Orient Petroleum International Inc., to acquire a 51.3% working interest, along with operatorship, in two joint venture blocks, Mirpurkhas and Khipro, located in the southern Sindh province of Pakistan.

On 22 December 2008, BP signed a production-sharing contract with the Indian government for a deepwater exploration block in the Krishna-Godavari Basin, offshore eastern India, which was awarded under the New Exploration Licensing Policy Seventh round. BP is the designated operator with a 30% working interest in the block. Reliance Industries Limited holds the remaining 70% working interest.

Midstream activities

Oil and natural gas transportation

The group has direct or indirect interests in certain crude oil transportation systems, the principal ones being the Trans-Alaska Pipeline System (TAPS) in the US, the Forties Pipelines System (FPS) in the UK sector of the North Sea and the Baku-Tbilisi-Ceyhan (BTC) oil pipeline.

In addition to these, we also operate the Central Area Transmission System (CATS) for natural gas in the UK sector of the North Sea, the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia (as operator of AIOC), and, as technical operator, the South Caucasus Pipeline (SCP) (BP 25.5%), which takes gas from Azerbaijan through Georgia to the Turkish border.

BP s onshore US crude oil and product pipelines and related transportation assets are included under Refining and Marketing (*see page 27).*

Assets and activity during 2008 included:

Alaska

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. Production transported by TAPS from Alaska North Slope fields averaged 700mb/d during 2008.

Work on the strategic reconfiguration project to upgrade and automate four TAPS pump stations continued to progress in 2008. This project is installing electrically-driven pumps at four critical pump stations, along with increased automation and upgraded control systems. Two of the reconfigured pump stations came online during 2007. The remaining two reconfigured pump stations are expected to come online sequentially, one in 2009 and one in 2010.

On 8 April 2008, BP and ConocoPhillips announced the formation of a joint venture company called Denali The Alaska Gas Pipeline. The joint venture has begun work on an Alaska gas pipeline project consisting of a gas treatment plant on Alaska s North Slope, a large-diameter pipeline that is intended to pass through Alaska into Canada, and should it be required, a large-diameter pipeline from Alberta to the Lower 48 United States. When completed, the pipeline is expected to move approximately 4 billion cubic feet of natural gas per day to market. The joint venture plans to spend up to $600 million prior to reaching the first major project milestone, an open season ,

before the end of 2010. An open season is a process during which
the joint venture seeks customers to make firm, long-term transportation commitments to the project. Should the open season be successful, the joint venture will seek certification from the Federal Energy Regulatory Commission (FERC) of the US and the National Energy Board (NEB) of Canada to move forward with project construction. The new joint venture company will manage the project, and will own and operate the pipeline when completed. BP and ConocoPhillips may consider other equity partners, including pipeline companies, who can add value to the project and help manage the risks involved. On 22 May 2008, the office of the Governor of Alaska announced that it would be supporting an alternative gas pipeline project proposed by TransCanada Alaska Company in response to the State of Alaska s request for bids under the Alaska Gas Inducement Act (AGIA) in 2007. BP s commitment to move forward with the Denali project is independent of any decisions made or inducement offered by the State under the AGIA process and BP believes that the Denali project offers the best opportunity for a successful Alaska gas pipeline project.

Alaska state courts issued two noteworthy rulings in 2008, related to challenges filed by in-state refiners against BP and the other TAPS carriers, regarding intrastate tariffs charged for shipping oil through TAPS during the period from 1997 through 2003. These rulings are related to long-standing challenges that were originally filed with the Regulatory Commission of Alaska (RCA). In 2002, the RCA issued Order 151, which determined that TAPS transportation rates charged from the beginning of 1997 were excessive, and that refunds should be paid. BP and the other TAPS carriers appealed the RCA's 2002 ruling in the State of Alaska court system. In the interim, the RCA issued Order 34, which imposed intrastate tariff rates consistent with Order 151, effective from 1 July 2003 forward. On 15 February 2008, the Alaska Supreme Court affirmed the determination in RCA's Order 151, and on 26 February 2008, the Alaska Superior Court affirmed the RCA's Order 34, and imposed the application of Order 151 to intrastate tariff rates charged from 2001 forward. BP and the other TAPS carriers decided not to appeal these matters any further in the courts, and on 25 March 2008, BP Pipelines Alaska paid refunds to intrastate shippers totalling $71 million covering the period 1997 through 2000. During the third quarter of 2008, BP Pipelines Alaska paid out an additional $75 million to intrastate shippers covering the period from 2001 through 30 June 2003. In 2008, intrastate transport made up approximately 13.7% of total TAPS throughput.

Tariffs for interstate transportation of oil through TAPS are calculated using the TAPS Tariff Settlement Methodology (TSM), which is defined in an agreement entered into with the State of Alaska in 1985. The TSM was also accepted at that time by the Regulatory Commission of Alaska (RCA) and the Federal Energy Regulatory Commission (FERC). Since then, Anadarko, Tesoro, and the State of Alaska have challenged the interstate tariffs charged by BP and the other TAPS carriers in the years 2005, 2006 and 2007 with the FERC. Anadarko and the State of Alaska have also challenged the 2008 tariffs. In 2006, the FERC consolidated the proceedings related to the years 2005-2006, and determined that the challenges pertaining to 2007 tariff rates would be held in abeyance until a decision was issued in the proceedings on 2005 and 2006 tariff rates. The FERC s hearings on the consolidated proceedings commenced in October 2006 and concluded in January 2007. On 17 May 2007, a FERC Administrative Law Judge (ALJ) issued an initial decision on 2005 and 2006 tariff rates that was adverse to BP and the other TAPS carriers, and established a floor of $3.01/bbl for the 2005-2006 period, as this was the last uncontested tariff rate. On 20 June 2008, the FERC issued a ruling on the 2005-2006 period, which substantially affirmed the initial ruling by the ALJ, and ordered the TAPS carriers to pay refunds to shippers. On 20 November 2008, the FERC affirmed its 20 June 2008 ruling in response to applications for rehearing filed by BP and the other TAPS carriers. Accordingly, in December 2008 BP as

Performance review

a TAPS carrier paid third party shippers tariff refunds of $52 million; and BP as a TAPS shipper received tariff refunds from third party carriers of $27 million. The FERC s 20 November 2008 ruling also concluded that a unified tariff rate should be established for interstate transportation through TAPS, and the TAPS carriers were ordered to implement a revenue pooling methodology in the TAPS Operating Agreement. Some TAPS carriers other than BP have filed legal challenges to this aspect of the FERC s 20 November 2008 ruling, which are still pending. As of the end of 2008, there have been no proceedings in the challenges to BP s and the other TAPS carriers 2007 and 2008 tariff rates. In 2008, interstate transport made up approximately 86% of total TAPS throughput.

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from more than 50 fields in the Central North Sea. The system has a capacity of more than one million barrels per day, with average throughput in 2008 of 662mb/d.

BP operates and has a 29.5% interest in CATS, a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1,700mmcf/d to a natural gas terminal at Teesside in north-east England. CATS offers natural gas transportation and processing services. In 2008, throughput was 836mmcf/d (gross), 247mmcf/d (net).

BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe oil and gas terminal in Shetland.

Asia (including the former Soviet Union)

BP as operator, manages and holds a 30.1% interest in the BTC oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oil field in the Caspian Sea to the eastern Mediterranean port of Ceyhan. The Turkish section of the pipeline is operated by Botas.

On 6 August 2008, the Baku-Tbilisi-Ceyhan (BTC) pipeline was shut down for 14 days as a result of a fire that occurred at Block Valve 30, located in the Erzincan province in Eastern Turkey. The pipeline restarted on 20 August 2008. The Azeri-Chirag-Gunashli (ACG) and Shah Deniz (SD) fields reduced offshore production to manage stock levels at the Sangachal Terminal. Some exports were maintained via the Northern Route Export Pipeline (NREP) and by rail through Georgia.

BP is technical operator of, and holds a 25.5% interest in, the 693-kilometre South Caucasus Pipeline (SCP), which takes gas from Azerbaijan through Georgia to the Turkish border. During August 2008, the South Caucasus gas and Western Route oil export pipelines were shut down for a short period as a precautionary measure during a period of military activity in the region.

In February 2008, BP, on behalf of AIOC, handed over operatorship of the Azerbaijani section of the NREP between Azerbaijan and Russia to the State Oil Company of Azerbaijan Republic (SOCAR).

Through the LukArco joint venture, BP holds a 5.75% interest in the Caspian Pipeline Consortium (CPC) pipeline and a 2.3% interest in Tengizchevroil (TCO). CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk and carries crude oil from a number of Kazakh fields, including Tengiz. In addition to our interest in LukArco, we hold a separate 0.87% interest in CPC through a 49% holding in Kazakhstan Pipeline Ventures (KPV). In 2008, CPC total throughput reached 32.2 million tonnes. During 2008, the majority of shareholders in CPC agreed on the commercial terms for expansion of CPC to 67 million tonnes. These terms strongly favour the upstream, and as BP has no additional volumes of Kazakh crude to ship in an expanded CPC, BP has been unable to support these new commercial terms. In order not to delay the expansion of CPC, BP has obtained the agreement of its KPV joint venture partners and CPC shareholders to dispose of its interest in KPV and is seeking the agreement of its joint venture partners, CPC shareholders and TCO partners to dispose of its interest in LukArco.

On 25 September 2008, Chevron announced that Tengizchevroil had completed a major expansion at the Tengiz field in Kazakhstan in which BP holds a 2.3% interest through its joint venture with LukArco. The completion of the expansion brings daily crude capacity of the field to 540mb/d.

Liquefied natural gas

Our LNG activities are focused on building competitively advantaged liquefaction projects, establishing diversified market positions to create maximum value for our upstream natural gas resources and capturing third party LNG supply to complement our equity flows.

Assets and activity during 2008 included:

In Trinidad, BP s net share of the capacity of Atlantic LNG Trains 1, 2, 3 and 4 is 6 million tonnes of LNG per year (292 billion cubic feet equivalent re-gasified), with the Atlantic LNG Train 4 (BP 37.8%) designed to produce 5.2 million tonnes (253 billion cubic feet) per year of LNG. All of the LNG from Atlantic Train 1 and most of the LNG from Trains 2 and 3 is sold to third parties in the US and Spain under long-term contracts. All of BP s LNG entitlement from Atlantic LNG Train 4 and some of its LNG entitlement from Trains 2 and 3 is marketed via BP s LNG marketing and trading business to a variety of markets including the US, the Dominican Republic, Spain, the UK and the Far East.

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2008 supplied 5.8 million tonnes (298.746mmcf) of LNG, up 3% from 2007.

BP has a 13.6% share in the Angola LNG project, which is expected to receive approximately one billion cubic feet of associated gas per day from offshore producing blocks and to produce 5.2 million tonnes gross per year of LNG, as well as related gas liquids products. With the completion of the necessary agreements and the approval of the Angolan government, the project investors have authorized Angola LNG Limited to proceed with the construction and implementation of the project.

In Indonesia, BP is involved in two of the three LNG centres in the country. BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga currently delivers around 13% of the total gas feed to Bontang, one of the world s largest LNG plants. The Bontang plant produced 18.4 million tonnes of LNG in 2008.

Also in Indonesia, BP has interests in the Tangguh LNG joint venture (BP 37.2% and operator) and in each of the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in north-west Papua that are expected to supply feed gas to the Tangguh LNG plant. During 2008, construction continued on two LNG trains and the offshore facilities, with commercial delivery planned in the second quarter of 2009. Tangguh will be the third LNG centre in Indonesia, with an expected initial capacity of 7.6 million tonnes of LNG (388,000mmcf) per year. Tangguh has signed LNG sales contracts for delivery to China, Korea and North America.

In Australia, we are one of seven partners in the North West Shelf (NWS) venture. The joint venture operation covers offshore production platforms, an FPSO, trunklines, onshore gas and LNG processing plants and LNG carriers. BP s net share of the capacity of NWS LNG Trains 1-5 is 2.7 million tonnes of LNG per year.

BP has a 30% equity stake in the 7 million tonne per annum capacity Guangdong LNG re-gasification and pipeline project in south-east China, making it the only foreign partner in China s LNG import business. In addition to LNG supplied under a long-term contract with Australia s NWS project, the terminal took delivery of an additional eight spot LNG cargoes during 2008, to meet rapidly growing local demand for gas.

Performance review

BP Shipping took delivery of four LNG ships during 2007 and 2008. The Gem class ships can carry 155,000m^3 of LNG and are among the first ships in the industry to be powered by low-emission, fuel-efficient, diesel-electric propulsion. BP Shipping provides safe, environmentally responsible marine and shipping solutions in support of BP group activities.

In both the Atlantic and Asian regions, BP is marketing LNG using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point and Elba Island) and the UK (via the Isle of Grain), and is supplying Asian customers in Japan, South Korea and Taiwan.

Gas marketing and trading activities

Gas and power marketing and trading activity is undertaken primarily in the US, Canada, the UK and Europe to market both BP production and third-party natural gas and manage market price risk as well as to create incremental trading opportunities through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhanced margins from sources such as the management of price risk on behalf of third-party customers. These markets are large, liquid and volatile.

In connection with the above activities, the group uses a range of commodity derivative contracts and storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the marketplace. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets. Natural gas futures and options are traded through exchanges, while over-the-counter (OTC) options and swaps are used for both gas and power transactions through bilateral and/or centrally cleared arrangements. Futures and options are primarily used to trade the key index prices such as Henry Hub, while swaps can be tailored to price with reference to specific delivery locations where gas and power can be bought and sold. OTC forward contracts have evolved in both the US and UK markets, enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used both to sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. Storage and transportation contracts allow the group to store and transport gas, and transmit power between these locations. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, which is described in Note 28 to the Financial statements on pages 140-145.

The range of contracts that the group enters into is described below in more detail:

Exchange-traded commodity derivatives

Exchange-traded commodity derivatives include gas and power futures contracts. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in total revenues for accounting purposes.

OTC contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used for both trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in total revenues for accounting purposes. Highly developed markets exist in North America and the UK where gas and power can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, these contracts specify delivery terms for the underlying commodity. Certain of these transactions are not settled physically. This can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume and price are the main variable terms. Swaps can be contractual obligations to exchange cash flows between two parties. One usually references a floating price and the other a fixed price, with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell natural gas products or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price, typically an index price prevailing on the delivery date when title to the inventory passes. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of third-party gas and sales of the group s gas production to third parties. Spot and term sales are included in total revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Performance review

Refining and Marketing

Our Refining and Marketing business is responsible for the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum, chemicals products and related services to wholesale and retail customers. BP markets its products in more than 100 countries. We operate primarily in Europe and North America and also manufacture and market our products across Australasia, in China and other parts of Asia, Africa and Central and South America.

In 2008 we restructured the Refining and Marketing organization into two main business groupings: fuels value chains (FVCs) and international businesses (IBs). The FVCs integrate the activities of refining, logistics, marketing, supply and trading, on a regional basis, recognizing that the markets for our main fuels products operate regionally. This shift to a more geographic and integrated model represents a major simplification step and the opportunity to create better value from our physical assets (refineries, terminals, pipelines and retail stations). The IBs include the manufacturing, supply and marketing of lubricants, petrochemicals, liquefied petroleum gas (LPG) and aviation and marine fuels. We believe each of these IBs is competitively advantaged in the markets in which we have chosen to participate. Such advantage is derived from several factors, including location, proximity of manufacturing assets to markets, physical asset quality, operational efficiency, technology advantage and the strength of our brands. Each business has a clear strategy focused on investing in its key assets and market positions in order to deliver value to its customers and outperform its competitors.

During the past five years, our focus has been on process safety, upgrading organizational capability and significant integrity management investment. The construction of new production units at many of our refineries as well as upgrades of existing conversion units at a number of our facilities has positioned our assets to produce the high-quality fuels needed to meet today s heightened product specifications.

Our performance in 2008

The 2008 environment in which the segment operated was very challenging, characterized by high and volatile crude and product prices, which resulted in substantial margin volatility as well as higher energy costs in manufacturing. Crude prices fell significantly in the second half of the year and at the end of the year, prices were around $50/bbl lower than the start of the year. Refining margins in the US were significantly weaker than 2007 due to weaker gasoline demand. Conversely, in Europe, where diesel accounts for a larger share of regional demand, margins were stronger than a year ago. Demand for fuels has fallen, initially due to high oil prices and subsequently due to the slowing of global economies and the impact of the financial crisis. During the fourth quarter, we saw a dramatic decline in the demand for our petrochemicals products as a consequence of the economic slowdown. The year also saw material swings in foreign exchange rates, particularly in the second half, that affected our results.

Our 2008 performance reflects the benefits of the fundamental improvements we are making across the business, including the measures we have taken to restore the availability of our refining system, reduce costs and simplify the organization. The loss before interest and tax was $1.9 billion for 2008, compared with a profit before interest and tax of $6.1 billion in 2007. The decrease was primarily driven by inventory-holding losses. Our financial results are discussed in more detail on pages 50-51.

Safety, both process and personal, remains our top priority. During 2008, we started the migration to the new BP Operating Management System (OMS) with an increased focus on process safety and continuous improvement. The OMS is described in further detail on page 40. At the end of the year, two of our petrochemicals plants in the US and two of our refineries in Europe were operating on OMS. Within our US refineries, we continue to implement the recommendations from the BP US Refineries Independent Safety Review Panel. We have worked closely with the independent expert, L Duane Wilson. The number of major incidents associated with integrity management has decreased by 90% since 2005. We have also reduced the number of oil spills by 60% and the recordable injury rate by more than 57% since 1999. Regrettably, in 2008 there were four workforce fatalities associated with our operations, one of which was a process safety incident.

In 2008, we saw the first substantial benefits of our operational improvements. The Whiting refinery was restored to its full clean fuel capability of 360mb/d in March 2008 following the compressor failure and fire that took place during 2007. Texas City was also restored to full economic capability by the end of the year. In Europe and Rest of World, we commissioned new upgrading units at the Rotterdam and Kwinana refineries, enhanced processing capability at the Gelsenkirchen refinery, reconfigured the Bayernoil refinery for more efficient and competitive operation, and completed construction of a new coker at the Castellón refinery. During the next five years, we intend to continue the focus on process safety, improve the competitive performance of our refineries and complete the previously announced investment in the Whiting refinery to increase its ability to process Canadian heavy crude.

In total, our 17 refineries worldwide, including those partially owned, achieved throughputs of 2,155mb/d on average, a 5% increase on 2007 after adjusting for the net loss of throughput from previous disposals and acquisitions. The performance of Texas City was impacted by Hurricane Ike in September, which meant we had to shut down the refinery in advance as a precautionary measure, along with other refineries in the area. Operational disruption was minimized as crude processing was restored in seven days and full operations restored within three weeks. This was due to a terrific response from employees and also reflected the improvements we have made to our assets at Texas City over the last few years.

During 2008, we fully integrated our refining, logistics, marketing, supply and trading activities, establishing six refining-to-marketing integrated FVCs focused on refining and selling ground transportation fuels in each region. This has enabled us to simplify internal interfaces, optimize margins, reduce overhead costs and drive continuous improvement. During the year, we continued the implementation of our ampm convenience retail franchise model in the US, which we expect to provide reliable long-term sales growth for our refinery systems, together with reduced costs and lower levels of capital investment. In Europe, where we are one of the largest forecourt convenience retailers, with about 2,500 shops in 10 countries, we are growing our food-on-the-go and fresh grocery services through BP-owned brands and partnerships with leading retailers such as Marks & Spencer.

In relation to our IBs during 2008, in the lubricants business we focused on enhancing our customer relationships and brand distinctiveness, together with simplifying operations and improving efficiency. Although 2008 was a difficult year for the aviation industry, in Air BP, we simplified our footprint by exiting non-core countries resulting in a reduction in working capital and improved returns on operating capital employed. During the year, the environment in which our petrochemicals businesses operate became more challenging as deterioration in the global economic market led to reduced demand for our products.

We are simplifying the structure of our organization, improving the efficiency of our back office and reducing our headcount, including the number of senior management positions.

Performance review

Looking ahead, in 2009 the overall economic environment is expected to be challenging with reduced demand for our products leading to lower volumes and pressure on margins. The impact is expected to be greatest in the petrochemicals sector.

Against this background, we intend to continue actively managing our cost base, simplifying our marketing footprint and developing the market positions where we have competitive advantage based on brand and technology strengths. We also intend to improve the efficiency of our back office, including customer service, accounting services and procurement systems, by centralizing these activities in a few global centres to remove duplication and reduce cost. We intend to focus on cash generation through active management of our working capital and credit exposure.

We intend to limit our capital investment to maintaining and improving our core positions. To continue the progress we have made in recent years, our top priority for spending will remain safety and operational integrity. The other area of focus will be delivering integrated value in our key markets through investment in terminals and pipeline infrastructure. Our largest investment is expected to be at the Whiting refinery, where we have started a major upgrading and modernization programme that will enable the refinery to operate on Canadian heavy crude oil. We also intend to complete the planned projects in petrochemicals *(see page 32)*.

Comparative information presented in the table below has been restated, where appropriate, to reflect the resegmentation, following transfers of businesses between segments, that was effective from 1 January 2008. See page 12 for further details.

Key statistics

			$ million
	2008	2007	2006
Total revenues[a]	**320,458**	250,897	232,833
Profit before interest and tax from continuing operations[b]	**(1,884)**	6,076	5,419
Total assets	**75,329**	95,311	80,738
Capital expenditure and acquisitions	**6,634**	5,495	3,127
			$ per barrel
Global Indicator Refining Margin[c]	**6.50**	9.94	8.39

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

[c] The Global Indicator Refining Margin

(GIM) is the average of regional industry indicator margins, which we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

Total revenues are analysed in more detail below.

			$ million
	2008	2007	2006
Sale of crude oil through spot and term contracts	**54,901**	43,004	38,577
Marketing, spot and term sales of refined products	**248,561**	194,979	177,995
Other sales and operating revenues	**16,577**	12,238	15,814
Earnings from equity-accounted entities (after interest and tax), interest, and other revenues	**419**	676	447
	320,458	250,897	232,833

			thousand barrels per day
Sale of crude oil through spot and term contracts	**1,689**	1,885	2,110
Marketing, spot and term sales of refined products	**5,698**	5,624	5,801

			thousand barrels per day
Sales of refined products[a]	**2008**	2007	2006
Marketing sales			
UK[b]	**310**	339	356
Rest of Europe	**1,256**	1,294	1,340
US	**1,460**	1,533	1,595
Rest of World	**685**	640	581
Total marketing sales[c]	**3,711**	3,806	3,872
Trading/supply sales[d]	**1,987**	1,818	1,929
Total refined products	**5,698**	5,624	5,801

			$ million
Proceeds from sale of refined products	**248,561**	194,979	177,995

[a] Excludes sales to other BP businesses, sales of Aromatics & Acetyls products and Olefins & Derivatives sales through equity-accounted entities.

[b] UK area includes the UK-based international activities of Refining and Marketing.

[c] Marketing sales are sales to service stations, end-consumers, bulk buyers and jobbers (i.e. third parties who own networks of a number of service stations and small resellers).

[d] Trading/supply sales are sales to large unbranded resellers and other oil companies.

The following table sets out marketing sales by major product group.

			thousand barrels per day
Marketing sales by refined product	**2008**	2007	2006
Aviation fuel	**501**	490	488
Gasolines	**1,500**	1,572	1,603
Middle distillates	**1,055**	1,119	1,170
Fuel oil	**460**	429	388
Other products	**195**	196	223
Total marketing sales	**3,711**	3,806	3,872

Marketing volumes were 3,711mb/d, slightly lower than last year, reflecting the impacts from the slowing of global economies and reduced industry demand in the US and Europe.

Fuels value chains

Following our reorganization we have six integrated FVCs. They are organized regionally, covering the West Coast and Mid-West regions of the US, the Rhine region, Southern Africa, Australasia (ANZ) and Iberia. Each of these is a material business, optimizing activities across the supply chain from crude delivery to the refineries; manufacture of high-quality fuels to meet market demand; pipeline and terminal infrastructure and the marketing and sales to our customers. The Texas City refinery is operated as a standalone predominantly merchant refining business that also supports our marketing operations on the east and gulf coasts.

Refining

The group s global refining strategy is to own and operate strategically advantaged refineries that benefit from vertical integration with our marketing and trading operations, as well as horizontal integration with other parts of the group s business. Refining s focus is to maintain and improve its competitive position through sustainable, safe, reliable and efficient operations of the refining system and disciplined investment for integrity management, to achieve competitively advantaged configuration and growth.

For BP, the strategic advantage of a refinery relates to its location, scale and configuration to produce fuels from lower-cost feedstocks in line with the demand of the region. Strategic investments in our refineries are focused on securing the safety and reliability of our assets while improving our competitive position. In addition, we continue to invest to develop the capability to produce the cleaner fuels that meet the requirements of our customers and their communities.

Performance review

The following table summarizes the BP group s interests in refineries and crude distillation capacities at 31 December 2008.

				thousand barrels per day Crude distillation capacities[a]	
	Refinery	Fuels value chain	Group interest[b] %	Total	BP share
Rest of Europe					
Germany	Bayernoil	Rhine	22.5%	215	48
	Gelsenkirchen*	Rhine	50.0%	266	133
	Karlsruhe	Rhine	12.0%	323	39
	Lingen*	Rhine	100.0%	93	93
	Schwedt	Rhine	18.8%	226	42
Netherlands	Rotterdam*	Rhine	100.0%	386	386
Spain	Castellón*	Iberia	100.0%	110	110
Total Rest of Europe				1,619	851
US					
California	Carson*	US West Coast	100.0%	266	266
Washington	Cherry Point*	US West Coast	100.0%	234	234
Indiana	Whiting*	US Mid-West	100.0%	405	405
Ohio	Toledo*	US Mid-West	50.0%	155	78
Texas	Texas City*		100.0%	475	475
Total US				1,535	1,458
Rest of World					
Australia	Bulwer*	ANZ	100.0%	102	102
	Kwinana*	ANZ	100.0%	137	137
New Zealand	Whangerei	ANZ	23.7%	102	24
Kenya	Mombasa[c]	Southern Africa	17.1%	94	16
South Africa	Durban	Southern Africa	50.0%	180	90
Total Rest of World				615	369
Total				3,769	2,678

*Indicates refineries operated by BP.

[a]Crude distillation capacity is gross rated capacity, which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

[b]BP share of equity, which is not necessarily the same as BP share of processing entitlements.

[c]On 15 January 2008, it was announced that Essar Energy Overseas Ltd, a subsidiary of Essar Oil Limited, had entered into an agreement to acquire 50% of Kenya Petroleum Refineries Ltd.

The transaction was initially expected to be finalized in 2008, but has since been delayed in negotiations.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties. Corresponding BP refinery capacity utilization data is summarized.

	thousand barrels per day		
Refinery throughputs[a]	**2008**	2007	2006
UK		67	165
Rest of Europe	**739**	691	648
US	**1,121**	1,064	1,110
Rest of World	**295**	305	275
Total	**2,155**	2,127	2,198
Refinery capacity utilization			
Crude distillation capacity at 31 December[b]	**2,678**	2,769	2,823
Crude distillation capacity utilization[c]	**78%**	72%	76%
US	**72%**	62%	70%
Europe	**85%**	84%	87%
Rest of World	**83%**	84%	78%

[a]Refinery throughputs reflect crude and other feedstock volumes.

[b]Crude distillation capacity is gross rated capacity, which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

[c]Crude distillation capacity utilization is defined as the percentage utilization of capacity per calendar day during the year after making allowances for average annual shutdowns at BP refineries (i.e. net rated capacity).

Performance review

Excluding portfolio impacts, underlying refining throughputs in 2008 increased by 5% relative to 2007, driven principally by improved operational performance in the US. Higher US throughputs were attributable to the recoveries at the Texas City and Whiting refineries, partially offset by the reduced equity interest in the Toledo refinery stemming from the Husky joint venture (see below). The improvement achieved in the US was lower than it would have been as crude runs were reduced as a result of the low-margin environment as well as the disruption at the Texas City refinery in September caused by Hurricane Ike.

The increase in Rest of Europe throughputs in 2008 is primarily related to the purchase of Chevron s 31% interest in the Rotterdam refinery in 2007. The decrease in UK throughputs is due to the sale of the Coryton refinery to Petroplus.

Significant events in Refining were as follows:

On 21 March 2008, the Whiting refinery in the US was restored to its full clean fuel capability of 360mb/d.

BP completed recommissioning the Texas City refinery in the US. With the successful return to service of Ultraformer No. 3 in the fourth quarter, the site s full economic capability was restored.

On 31 March 2008, we completed a deal with Husky Energy Inc. to create an integrated North American oil sands business by means of two separate joint ventures, one of which entailed Husky taking a 50% interest in BP s Toledo refinery. The Toledo refinery is intended to be expanded to process approximately 170mb/d of heavy oil and bitumen by 2015.

In July, a final investment decision was taken to progress the significant upgrade of the Whiting refinery. This project repositions Whiting competitively by increasing its Canadian heavy crude processing capability by 260mb/d and modernizing it with equipment of significant size and scale.

On 17 March 2008, BP and Irving Oil entered into a memorandum of understanding to work together on evaluating the feasibility of the proposed Eider Rock refinery in Saint John, New Brunswick, Canada.

Fuels marketing, supply and logistics

Our fuels marketing strategy focuses on optimizing the integrated value of each fuels value chain that is responsible for the delivery of ground fuels to the market. We do this by co-ordinating our marketing, refining and trading activities to maximize synergies across the whole value chain. Our priorities are to operate an advantaged infrastructure and logistics network (which includes pipelines, storage terminals and road or rail tankers), drive excellence in operating and transactional processes and deliver compelling customer offers in the various markets where we operate. The fuels business markets a comprehensive range of refined oil products primarily focused on the ground fuels sector.

On 29 August 2008, BP announced an agreement with Enbridge Inc. to build and reconfigure a pipeline system to transport Canadian heavy crude oil from Flanagan, Illinois, to Houston and Texas City, Texas. The system is expected to be in service by late 2012 with an initial capacity of 250mb/d. The joint investment of the phased capacity additions is expected to be in the range of $1-2 billion.

The ground fuels business supplies fuel and related convenience services to retail consumers through company-owned and franchised retail sites as well as other channels including wholesalers and jobbers. It also supplies commercial customers within the road and rail transport sectors.

BP s value creation in ground fuels is obtained through the integration of the value chain from the refinery gates or import hubs across retail and commercial channels to market. Convenience retail offers are focused on delivering appealing convenience offers across the various markets in which we operate, through the BP Connect, ampm and Aral brands.

Our retail network is largely concentrated in Europe and the US, and also has established operations in Australasia and southern and eastern Africa. We are developing networks in China in two separate joint ventures, one with Petrochina and the other with China Petroleum and Chemical Corporation (Sinopec).

Retail sites[a b]	Number of retail sites operated under a BP brand **2008**	2007	2006
UK	**1,200**	1,200	1,300
Rest of Europe	**7,400**	7,400	7,700
US (excluding jobbers)	**2,500**	2,500	2,700
US jobbers	**9,200**	9,700	9,600
Rest of World	**2,300**	2,500	2,600
Total	**22,600**	23,300	23,900

[a] Changes in the number of retail sites over time are affected by, among other things, dealer/jobber-owned sites that move to or from the BP brand as their fuel supply agreements expire and are renegotiated in the normal course of business.

[b] Excludes our interest in equity-accounted entities. Comparative information has been amended to this basis.

At 31 December 2008, BP s worldwide network consisted of some 22,600 locations branded BP, Amoco, ARCO and Aral, around the same as in the previous year. We continue to improve the efficiency of our retail network and increase the consistency of our site offer through a process of regular review. In 2008, we sold 470 company-owned sites to dealers, jobbers and franchisees who continue to operate these sites under the BP brand. We also divested an additional 160 company-owned sites to third parties.

At 31 December 2008, BP s retail network in the US comprised approximately 11,700 sites, of which approximately 9,200 were owned by jobbers and 900 operated under a franchise agreement. In November 2007, BP announced that it would sell all of its company-owned and company-operated convenience sites in the US. Despite the challenges in the global credit market, we expect the sale of these sites to be completed by the end of 2009. At the end of 2008, sales of 293 of sites had been successfully completed. The sites will continue to market BP-branded fuels in the eastern US and ARCO-branded fuels in the western US. The franchise agreement has a term of 20 years and requires sites to be supplied with BP- or ARCO-branded fuels for the term of the contract.

At the end of 2008, our European retail network consisted of approximately 8,600 sites and we had approximately 2,300 sites in the Rest of World.

Our retail convenience operations offer consumers a range of food, drink and other consumables and services on the fuel forecourt in a safe, convenient and innovative manner. With operations in both Europe and the US, using recognized and distinctive brands, BP is working to maximize the efficiency and effectiveness of its retail network in each of its chosen market areas. By the end of 2008, we completed the roll-out of more than 100 Marks & Spencer Simply Food sites as an integral part of the convenience network in the UK, while a refresh of the Petit Bistro brand in Germany and the Wild Bean Café brand in other European locations has re-energized consumers convenience shopping choices. In the US, BP has embarked on a roll-out of its successful ampm brand across all targeted national markets as its single convenience flagship; this programme roll-out is intended to be completed by the end of 2009.

Performance review

Supply and trading

The group has a long-established integrated supply and trading function responsible for delivering value across the overall crude and oil products supply chain. This structure enables BP to maintain a single face to the oil trading markets and to operate with a single set of trading compliance processes, systems and controls. Operating through trading offices located in Europe, the US and Asia, the function is able to maintain a presence in the regionally connected global markets.

The function seeks to identify the best markets and prices for our crude oil, source optimal feedstocks for our refineries and provide competitive supply for our marketing businesses. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. Wherever possible, the group will look to optimize value across the supply chain. For example, BP will often sell its own crude production into the market and purchase alternative crude for its refineries where this will provide incremental margin.

In addition to the supply activity described above, the function seeks to create incremental trading opportunities. It enters into the full range of exchange-traded commodity derivatives, over-the-counter (OTC) contracts and spot and term contracts that are described in detail below. In order to facilitate the generation of trading margin from arbitrage, blending and storage opportunities, it also both owns and contracts for storage and transport capacity. The group has developed a risk governance framework to manage and oversee the financial risks associated with this trading activity, which is described in the Financial statements Note 28 on pages 140-145.

The range of transactions that the group enters into is described below:

Exchange-traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX, ICE and Chicago Board of Trade. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate, and the main product grades, such as gasoline and gasoil. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of both crude oil and refined products. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in total revenues for accounting purposes.

OTC contracts

These contracts are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties; others may be cleared by a central clearing counterparty. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts are included in total revenues for accounting purposes.

The main grades of crude oil bought and sold forward using standard contracts are West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Osberg or BFO). Although the contracts specify physical delivery terms for each crude blend, a significant volume are not settled physically. The contracts typically contain standard delivery, pricing and settlement terms. Additionally, the BFO contract specifies a standard volume and tolerance given that the physically settled transactions are delivered by cargo.

Swaps are often contractual obligations to exchange cash flows between two parties: a typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude or oil products at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell crude and oil products at the market price prevailing on and around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of crude for a refinery, purchases of products for marketing, sales of the group s oil production and sales of the group s oil products. For accounting purposes, spot and term sales are included in total

revenues, when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.
International businesses
Our IBs provide quality products and offers to customers in more than 100 countries worldwide with a significant focus on Europe, North America and Asia. Our products include aviation and marine fuels, lubricants that meet the needs of various industries and consumers, LPG, and a range of petrochemicals that are sold for use in the manufacture of other products such as fabrics, fibres and various plastics.

Lubricants

We manufacture and market lubricants and related products and services to the automotive, industrial, marine and energy markets across the world. Following a decision to simplify and focus our channels of trade, we now sell products direct to our customers in around 50 countries and use approved local distributors for the remaining locations. Customer focus, distinctive brands, superior technology and relationships remain the cornerstones of our long-term strategy.

BP markets primarily through its major brands of Castrol and BP, plus the Aral brand in some specific markets. Castrol is recognized as one of the most powerful lubricants brands worldwide and we believe it provides us with a significant competitive advantage. In the automotive lubricants sector, we supply lubricants and other related products and services to intermediate customers such as retailers and workshops. These, in turn, serve end-consumers such as car, truck and motorcycle owners in the mature markets of Western Europe and North America as well as the markets of Russia, China, India, the Middle East, South America and Africa, which we believe have the potential for significant long-term growth.

BP s marine lubricants business is a global market leader, supplying many types of vessels from deep-sea fleets to marine leisure-craft from around 1,200 ports across the globe. BP s industrial lubricants business is a leading supplier to those sectors of the market involved in the manufacture of automobiles, trucks, machinery components and steel. BP is also a leading supplier of lubricants for the offshore oil and aviation industries.

Performance review

Petrochemicals

Our petrochemicals operations are comprised of the global Aromatics & Acetyls businesses (A&A) and the Olefins & Derivatives (O&D) businesses, predominantly in Asia. New investments are targeted principally in the higher growth Asian markets.

In A&A, we manufacture and market three main product lines: purified terephthalic acid (PTA), paraxylene (PX) and acetic acid. Our A&A strategy is to leverage our industry-leading technology in selected markets, to grow the business and to deliver industry-leading returns. PTA is a raw material used in the manufacture of polyesters used in fibres, textiles and film, and PET bottles. Acetic acid is a versatile intermediate chemical used in a variety of products such as paints, adhesives and solvents, as well as its use in the production of PTA. We have a strong global market share in the PTA and acetic markets with a major manufacturing presence in Asia, particularly China. PX is a feedstock for PTA production.

In O&D, we manufacture ethylene and propylene from naphtha and also produce a number of downstream derivative products.

Our O&D business has operations in both China and Malaysia. In China, our SECCO joint venture between BP, Sinopec and its subsidiary, Shanghai Petrochemical Company is the largest foreign-invested olefins cracker in China. SECCO is BP s single largest investment in China. This naphtha cracker produces ethylene and propylene plus derivatives acrylonitrile, polyethylene, polypropylene, styrene, polystyrene, and other products. In Malaysia, BP participates in two joint-ventures: Ethylene Malaysia Sdn. Bhd. (EMSB), which produces ethylene from gas feedstock in a joint venture between BP, Petronas and Idemitsu; while Polyethylene Malaysia Sdn. Bhd. (PEMSB) produces polyethylene in a joint venture between BP and Petronas. Each of these ventures has demonstrated a strong track record of project delivery and performance. BP also owns one other naphtha cracker outside Asia, which is integrated with our Gelsenkirchen refinery in Germany.

The following table shows BP s petrochemicals production capacity at 31 December 2008. This production capacity is based on the original design capacity of the plants plus expansions.

BP share of capacity

						thousand tonnes per year
Geographic area	PTA	PX	Acetic acid	Other	O&D	Total
US	2,385	2,373	546	151		5,455
Europe	1,075	622	544	158	1,629	4,028
Asia (excluding China)	2,209		815	56	257	3,337
China	1,554		215	51	2,290	4,110
	7,223	2,995	2,120	416	4,176	16,930

During 2008, the environment in which our petrochemicals businesses operate became more challenging as deterioration in the global economic environment has led to a reduced demand for our products.

Significant events in petrochemicals were as follows:

The second PTA plant at the BP Zhuhai Chemical Company Limited site in Guangdong province (China) successfully completed commissioning in the first quarter of 2008. This 900+ ktepa plant is the single largest PTA manufacturing train in the world and employs BP s latest, proprietary technology.

Construction continued on the new 500ktepa acetic acid plant in Jiangsu province (China) by BP YPC Acetyls Company (Nanjing) Limited (BYACO). This is a BP joint venture with Yangzi Petrochemical Co. Ltd (a subsidiary of Sinopec). Construction is scheduled to be completed in June 2009 with commercial sales expected to begin in the third quarter of 2009.

Commissioning of our expanded Geel (Belgium) PTA facility commenced at the end of 2008. The 350ktepa expansion improves overall operating costs and increases the site s PTA capacity to 1,425ktepa.

In January 2008, BP and Sinopec signed a memorandum of understanding to add a new acetic acid plant at their Yangtze River Acetyls Co. (YARACO) joint venture site in Chongqing (China). This world-scale (650ktepa) acetic acid plant will use BP s leading Cativa technology. The expected plant start-up date, which was originally anticipated to be during 2011, is under review due to the market conditions. When complete, total production at the YARACO site is expected to be well over one million tonnes per annum, making this one of the largest acetic acid production locations in the world.

Aviation and marine fuels

Air BP is one of the world s largest and best known aviation fuels suppliers, serving all the major commercial airlines as well as the general aviation and military sectors. During 2008, which was a tough year for the aviation industry, we simplified our geographical footprint by exiting non-core countries and now supply customers in approximately 70 countries. We have annual marketing sales in excess of 27 billion litres and we have relationships with many of the world s major commercial airlines. Air BP s strategic aim is to grow its position in the core locations of Europe, the US, Australasia and the Middle East, while focusing its portfolio towards airports that offer long-term competitive advantage. BP s marine fuels business focuses on the distribution and sale of refined fuel oils to the shipping industry at locations in more than 100 ports across the world. During 2008, this business performed well, supported by strong growth in the shipping market.

LPG

The LPG business sells bulk, bottled, automotive and wholesale LPG products to a wide range of customers in 13 countries. During the past few years, our LPG business has consolidated its position in established markets, pursued opportunities in new and emerging markets such as China and announced the exit from the Vietnam market in December 2008. LPG product sales in 2008 were approximately 68mbpd.

Performance review

Other businesses and corporate

Other businesses and corporate comprizes Treasury (which includes interest income on the group s cash and cash equivalents) and corporate activities worldwide, the group s aluminium asset, the Alternative Energy business and Shipping.

Comparative information presented in the table below has been restated, where appropriate, to reflect the resegmentation, following transfers of businesses between segments, that was effective from 1 January 2008. See page 12 for more details.

Key statistics

			$ million
	2008	2007	2006
Total revenues[a]	**5,040**	3,972	3,703
Profit (loss) before interest and tax from continuing operations[b]	**(1,258)**	(1,233)	(779)
Total assets	**19,079**	20,595	16,315
Capital expenditure and acquisitions	**1,839**	939	852

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

Treasury

Treasury co-ordinates the management of the group s major financial assets and liabilities. From locations in the UK, the US and the Asia Pacific region, it provides the link between BP and the international financial markets and makes available a range of financial services to the group, including supporting the financing of BP s projects around the world.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses are therefore borne as they arise, rather than being spread over time through insurance premiums with attendant transaction costs. This position is reviewed periodically.

Aluminium

Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, US. Production facilities are located in Logan County, Kentucky, and are jointly owned with Novelis. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business, which it manufactures primarily from recycled aluminium.

Alternative Energy

BP invested $1.4 billion in our Alternative Energy business during 2008, bringing the total investment in this business to $2.9 billion since its launch in 2005. We expect to fulfil our original 2005 commitment to invest a total of $8 billion over 10 years. In 2008, we prioritized four areas with significant long-term growth potential wind, solar, biofuels and carbon capture and storage (CCS). We have also developed a fifth area gas-fired power that offers synergies with other BP operations. We have concentrated our 2008 investment in these areas.

	2008	2007	2006

Wind net rated capacity as at year-end (megawatts)[a]	**432**	172	43
Solar cell production capacity as at year-end (megawatts)[b]	**213**	228	201

[a] Net wind capacity is the sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP s share of equity-accounted entities. The equivalent capacities on a gross-JV basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership) were 785MW in 2008, 373MW in 2007 and 43MW in 2006.

[b] Solar capacity is the theoretical cell production capacity per annum of in-house manufacturing facilities.

Wind

Since the launch of Alternative Energy we have substantially grown our wind portfolio, increasing from 32 megawatts (MW) in operation to 432MW (785MW gross) at the end of 2008. In total, we have more than 500MW (1,000MW gross) of installed capacity. This increase in capacity was led by the US with installations at Cedar Creek, Silver Star, Sherbino and Edom Hills.

To accelerate our growth in the US wind energy market, we acquired two fully integrated wind power development companies Greenlight Energy Inc. and Orion Energy LLC, during 2006. To secure the continuing availability of turbines we have signed agreements with Nordex (Germany) and GE (the US) for a combined 900MW to be delivered during the next two years. This is in addition to a five-year wind turbine contract we previously signed with Clipper Windpower Inc. in 2006.

We also operate wind farms in the Netherlands and in Maharashtra, India.

Solar

We continued to implement BP Solar s strategy to invest in lower cost manufacturing and technology to enable energy sourced from our products to compete with conventional electricity. Our global business model spans the entire solar value chain from the acquisition of silicon as a raw material, the production of wafers and cells to the creation of solar panels that are then sold and distributed as solar systems on the roofs of residential homes, large commercial buildings and on vacant land.

Today, BP Solar s main production facilities are located in Maryland (US), Madrid (Spain), Xi an (China) and Bangalore (India). During 2008, due to increasingly competitive market conditions, BP Solar announced plans to refocus operations at larger scale plants to achieve lower-cost manufacturing. This resulted in the start of an intensive programme of operational efficiency improvement in the remaining BP Solar plants and plans to close our manufacturing plant in Australia. During 2008, BP Solar signed contracts with a select set of third-party strategic partners in Asia who specialize in the production of low-cost, high-quality wafers, cells and modules.

During 2008, BP Solar achieved sales of 162MW, an increase of 41% from 115MW in 2007. The slight decrease in solar production capacity was due to fire damage in a section of our manufacturing plant in India.

Performance review

More than 70% of our sales volume is through third-party distributors in the residential markets in Europe, the US and Australasia. We have continued to roll out our Certified Installer Programme (CIP), first established in Germany, to ensure the safe, high-quality installation of products by third parties. The CIP has grown rapidly in Germany and this year has been rolled out in Spain and Australia.

In the US, in 2008, we continued to supply large corporations with sustainable energy solutions, completing a second solar system for FedEx Freight in California and a further six installations for Wal-Mart. In Europe, we expanded the relationship with Banco Santander to jointly build and finance a number of solar plants in Spain, with the construction of an 8 megawatts-peak (MWp) solar farm in Toledo and a 6MWp project in Tenerife. In Asia, we completed the installation of a solar power demonstration project (SolarSail) at the Guangdong Science Center; the SolarSail absorbs sunlight to produce power, while providing cool shade for visitors. In Australia, the largest roof-top solar system (100 kilowatt) in New South Wales commenced operation in February 2008, representing the first commercial solar power installation for the Blacktown Solar City Project. The Solar Cities Programme is a government initiative to implement distributed solar and other energy efficient technologies in seven Australian cities.

We are developing a new silicon growth process named Mono^{2} ™, which will increase cell efficiency over traditional multicrystalline-based solar cells. We have moved from a prototype to low-volume production and have converted our casting stations in Frederick, Maryland, delivering 1.2MW Mono^{2} ™. From the trials, we are seeing significant improvement in power and generated kWh when compared with multicrystalline-based solar cells particularly when modules are used where sunlight is low.

BP Solar has long-term relationships with world-class universities and invests in research programmes with organizations including the University of Delaware, California Institute of Technology (Cal Tech) and the Fraunhofer Institute (Germany). BP Solar was selected for the Solar America Initiative (SAI) award from the US Department of Energy a $40-million research and development programme aimed at decreasing the cost of solar cells and increasing their efficiency. BP Solar is also a member of the broad consortium led by DuPont in conjunction with the University of Delaware, funded by the Defense Advanced Research Projects Agency (DARPA), to develop high-efficiency solar cells.

Biofuels

BP has a key role to play in enabling the transport sector to respond to the dual challenges of energy security and climate change. Our investments are focused on sustainable feedstocks that minimize pressure on food supplies and on research into advanced technologies and practices to make good biofuels even better.

We have embarked on a focused programme of biofuels development based around the most efficient transformation of sustainable and low-cost sugars into a range of fuel molecules. These include bioethanol from Brazilian sugar cane, more efficient fuel molecules like biobutanol and advanced biofuels like lignocellulosic bioethanol produced from non-food energy grasses and for-purpose feedstocks such as miscanthus and energy cane.

BP has announced it has plans to invest in excess of $1 billion in building our own biofuels business operations, including partnerships with other companies to develop the technologies, feedstocks and processes required to produce advanced biofuels.

These investments include: a 50% stake in Tropical BioEnergia, a joint venture with Santelisa Vale and Maeda Group, to produce bioethanol from sugar cane; and a $90-million investment and strategic alliance with Verenium Corporation to accelerate the development and commercialization of biofuels produced from lignocellulosic bioethanol. We have been working with DuPont since 2003 to explore new approaches to the development of biofuels. The first product from this collaboration will be an advanced fuel molecule called biobutanol, which has a higher energy content than ethanol. We have partnered with ABF (British Sugar) and DuPont to construct a world-scale biofuels plant in Hull.

Innovation begins with research. In 2006, we announced plans to invest $500 million over 10 years in the Energy Biosciences Institute (EBI), at which biotechnologists are investigating applications of biotechnology to energy, including advanced fuels. This amount is incremental to the $1 billion of investments mentioned above. Our partners are the University of California, Berkeley and the University of Illinois at Urbana Champaign and the

Lawrence Berkeley National Laboratory. The EBI is focusing on the integrated development of better crops, better processing technologies and better biofuels, leading to cleaner energy.

Hydrogen power

In May 2007, BP and Rio Tinto announced the formation of a new jointly owned company, Hydrogen Energy International Limited, which will develop decarbonized energy projects around the world. The venture will initially focus on hydrogen-fuelled power generation, using fossil fuels and CCS technology to produce new large-scale supplies of clean electricity.

Hydrogen Energy is working on developing low-carbon power plants with projects in Abu Dhabi and California manufacturing hydrogen for power generation. In both instances, the captured CO_2 will be transported to nearby oil fields for use in enhanced oil recovery, with the CO_2 stored deep underground. General Electric and BP have formed a global alliance to jointly develop and deploy technology for hydrogen power plants that could significantly reduce emissions of the greenhouse gas CO_2 from electricity generation.

Through these initiatives, BP intends to continue to shape the development of the CCS value chain and to seek to minimize the carbon footprint exposure of the BP group as carbon pricing and policy develops globally.

Gas-fired power

Our gas-fired power activities comprise modern combined cycle gas turbine plants, which emit around 50% less CO_2 than a conventional coal plant of the same capacity, and several low-carbon co-generation gas power facilities. We have stakes in eight plants worldwide and this year increased the total power they are capable of producing from 5GW to 6GW and, where possible, we integrate plants with other BP production facilities. The Whiting Clean Energy facility, acquired in July 2008, now provides a reliable source of steam for our Whiting refinery and we are adding a 250MW steam turbine to our existing plant at our Texas City refinery. Our combined cycle plants are providing base-load demand for BP s major upstream gas production developments.

Performance review

Shipping

We transport our products across oceans, around coastlines and along waterways, using a combination of BP-operated, time-chartered and spot-chartered vessels. All vessels conducting BP activities are subject to our health, safety, security and environmental requirements.

International fleet

At the end of 2008, we had an international fleet of 54 vessels (37 medium-size crude and product carriers, four very large crude carriers, one North Sea shuttle tanker, eight LNG carriers and four LPG carriers). All these ships are double-hulled. Of the eight LNG carriers, BP manages one on behalf of a joint venture in which it is a participant and operates seven LNG carriers.

Regional and specialist vessels

In Alaska, during 2008, we redelivered one of our time-chartered vessels back to the owner, leaving a fleet of four double-hulled vessels. In the Lower 48, the two remaining heritage Amoco barges were phased out of BP s service. Outside the US, at the end of 2008, we had 14 specialist vessels (two double-hulled lubricants oil barges and 12 offshore support vessels).

Time-charter vessels

At the end of 2008, BP had 115 hydrocarbon-carrying vessels above 600 deadweight tonnes on time-charter, of which 107 are double-hulled and one is double-bottomed. All these vessels participate in BP s Time Charter Assurance Programme.

Spot-charter vessels

BP spot-charters vessels, typically for single voyages. These vessels are always vetted for safety assurance prior to use.

Other vessels

BP uses various craft such as tugs, crew boats and seismic vessels in support of the group s business. We also use sub-600 deadweight tonne barges to carry hydrocarbons on inland waterways.

Maritime security issues

2008 has seen a significant escalation in piracy activity, specifically off the north coast of Somalia. At a strategic level, BP avoids known areas of pirate attack or armed robbery; where this is not possible for trading reasons and we consider it safe to do so, we will continue to trade vessels through areas of known piracy, subject to the adoption of heightened security measures. BP will continue to route vessels through the Gulf of Aden for as long as it considers it to be safe to do so, having regard to available military and government agency advice. At present, we are following such advice and are participating in protective group transits through the Gulf of Aden Maritime Security Patrol Area transit corridor.

Performance review

Research and technology

Research and technology (R&T) has a critical role to play in addressing the world s energy challenges, from fundamental research through to wide-scale deployment. The full breadth of these R&T activities is carried out by each of the business segments. We also conduct long-term research within the central R&T group.

Inside the segments, research and technology activities are in service of competitive business performance and new business development, through the research, development or acquisition of new technologies. The central R&T group provides leadership for scientific and technological activities throughout the group and, in particular, provides input to the group s long-term strategy. It ensures that the right capability is in place in critical areas and ensures the quality of BP s major technology programmes. It also illuminates the potential of emerging technologies and conducts research and development (R&D) in support of BP s long-term corporate renewal. In addition, a group of eminent industrialists and academics forms the Technology Advisory Council, which advises the board and executive management on the state of research and technology within the group and helps to identify current trends and future developments in technology.

Research and development (R&D) is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of ideas and technologies to be considered and implemented, improving the impact of research and development activities.

Across the group, expenditure on R&D for 2008 was $595 million, compared with $566 million in 2007 and $395 million in 2006. See Financial statements note 15 on page 130. The 5% increase in 2008 compared with 2007 reflects increased investment in biosciences, conversion and carbon capture and storage technologies.

Beyond R&D, we also invest in technologies to get them to the point of commercial readiness: this includes field trials, support for technology deployment, specialist technical services and central investment in functional excellence and capability development have deepened our current areas of technology leadership.

In our Exploration and Production segment, we have organized leading technologies under 10 flagship programmes, each with the potential to add more than 1 billion boe to reserves through their development and deployment in our assets worldwide. These technologies contributed to exploration and production success in Algeria, Angola, Azerbaijan, Egypt, the North Sea and the Gulf of Mexico deepwater. Our advanced seismic imaging expertise, which is one of these programmes, continues to lead the industry, pioneering new wide-azimuth seismic acquisition and processing in deepwater Angola, Egypt and the Gulf of Mexico. In addition, BP has developed new technologies that have significantly reduced the time needed for land seismic acquisition in Oman, and these are now being deployed in Libya. Our enhanced oil recovery technologies are pushing recovery factors to new limits. For example, recovery factors have already increased from 40% to 60% in Alaska, where BP operates the world s largest miscible gas enhanced oil recovery project. BP also leads the industry in the application of new inter-well polymer treatments aimed at improving waterflood recovery, with more than 25 treatments delivering an increase of around five million barrels. Also in Alaska, BP s first hexalateral well came online in 2008 in the Orion field, which is capable of producing 9,500 barrels of oil per day the largest producer in BP s operations on the North Slope; while our first well using cold heavy oil production with sand (CHOPS) technology began producing heavy oil at a production rate of 100 barrels of oil per day. Unconventional gas is another area of focus; for example, using new technologies, BP has drilled in 17 unconventional coalbed methane basins around the world, including some of the largest reservoirs in North America. Another flagship programme is our use of digital technologies to optimize production and improve recovery, where BP has established an industry-leading position. In 2008, BP s oil and gas operations, enabled by real-time data and Field-of-the-Future® technologies delivered an extra 30,000 to 50,000 boepd gross production. Also in 2008, as part of its Inherently Reliable Facilities flagship, BP completed a field trial of a new fibre-optic system that represents a step-change in onshore pipeline monitoring, and which will now be deployed in Azerbaijan, Canada and Scotland.

In our Refining and Marketing segment, technology advancements are enabling our refineries to understand and process feedstocks of varying quality and optimize our assets in real time, enhancing the flexibility and reliability of our refineries and, in turn, improving the margins of our existing asset base. In 2008, BP began upgrading its Whiting refinery in Indiana to process heavy crude oil from Canada using one of the industry s most technologically advanced coking operations. In Naperville, US, we opened a new refining R&D centre, installing more than 50 new pilot units at the forefront of experimental technology and modelling. We have installed predictive analytics technology for fault detection and prediction on critical machinery across seven of our refineries reducing losses from machinery failure. BP s leading technologies in fuels and lubricants mean that it can keep ahead of increasingly stringent regulations, balancing greater fuel efficiency and performance and developing superior formulations across its entire product slate. For example, our BP Ultimate fuels deliver performance benefits such as improved fuel economy, lower emissions and a cleaner engine; and we have launched Greendeck and Greenfield, a suite of high-performance and environmentally friendly marine and offshore lubricants. Our proprietary processing technologies and operational experience continue to reduce the manufacturing costs and environmental impact of our petrochemicals plants, helping to maintain competitive advantage. For example, our new 900ktepa purified terephthalic acid (PTA) plant in Zhuhai, China was officially opened in 2008, occupying a plot just half the size of its older, neighbouring plant, but with double the production capacity. In the field of conversion technology, our Nikiski Fischer-Tropsch demonstration plant in Alaska operated at levels to prove that we have a working catalyst at industrial scale.

In Alternative Energy, our low-carbon research and technology activity continues apace. In 2008, we filed patents covering biofuels, carbon capture and storage (CCS), and hydrogen membranes. Our solar business produced the first prototype of a cut-cell high voltage module, giving a 5% increase in power over conventional modules. Working as part of the UK s Energy Technologies Institute a public/private partnership to accelerate low-carbon technology development BP is proceeding with investments in projects to develop new offshore wind and marine turbines. We also published results of the satellite monitoring programme, verified by well and tracer detection, of the CCS project at the In Salah gas field in Algeria with our partners Sonatrach.

Collaboration plays an important role across the breadth of BP s research and development activities, but particularly in those areas that benefit from fundamental scientific research. BP has 11 significant long-term research programmes with major universities and research institutions around the world, exploring areas from energy bioscience and conversion technology to carbon mitigation and nanotechnology in solar power. In 2008, our Energy Biosciences Institute at Berkeley (*see page 34*) became fully operational, with 49 research projects, all focused on lignocellulosic biofuel production; we announced the renewal of our Carbon Mitigation Initiative at Princeton; and signed the joint venture agreement for the Clean Energy Commercialisation Centre with the Chinese Academy of Sciences.

Performance review

Regulation of the group s business
BP s activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, alternative energy and shipping activities, are conducted in many different countries and are therefore subject to a broad range of EU, US, international, regional and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of our activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes and foreign exchange.

The terms and conditions of the leases, licences and contracts under which our oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements with governmental or state entities usually take the form of licences or production-sharing agreements. Arrangements with private property owners are usually in the form of leases.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

PSAs entered into with a government entity or state company generally require BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

In certain countries, separate licences are required for exploration and production activities and, in certain cases, production licences are limited to a portion of the area covered by the exploration licence. Both exploration and production licences are generally for a specified period of time (except for licences in the US, which typically remain in effect until production ceases). The term of BP s licences and the extent to which these licences may be renewed vary by area.

Frequently, BP conducts its exploration and production activities in joint venture with other international oil companies, state companies or private companies.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or production-sharing agreement). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, particularly in Angola, Norway, the UK, Russia, South America and Trinidad & Tobago.

For a discussion of environmental and certain health and safety regulations and environmental proceedings, see Environment on page 39. See also Legal proceedings on page 88.

Safety
This section reviews BP s safety performance in 2008.

There were five workforce fatalities in 2008, compared with seven in 2007. One resulted from fatal injuries sustained during operations at our Texas City refinery; one was the result of a fall from height at the Tangguh operations in Indonesia; one fatality was on a land farm near Texas City, and two were driving fatalities incidents in Mozambique and South Africa. We deeply regret this loss of life. By learning from these incidents and implementing appropriate improvement actions, we continue to seek to secure the safety of all members of our workforce. Our workforce reported recordable injury frequency, which measures the number of injuries per 200,000 hours worked, was 0.43 in 2008. This was a good improvement on the rate of 0.48 recorded in both 2007 and 2006.

Throughout 2008, senior leadership across the group continued to hold safety as their highest priority. Site visits, in which safety was a focus, were undertaken by the group chief executive (GCE) and members of the executive team to reinforce the importance of their commitment to safe and reliable operations.

Management systems

We continue to implement our new operating management system (OMS), a framework for operations across BP that is integral to improving safety and operating performance in every site.

When fully implemented, OMS will be the single framework within which we will operate, consolidating BP s requirements relating to process safety, environmental performance, legal compliance in operations, and personal, marine and driving safety. It embraces recommendations made by the BP US Refineries Independent Safety Review Panel (the panel), which reported in January 2007 on safety management at our US refineries and our safety management culture.

The OMS establishes a set of requirements, and provides sites with a systematic way to improve operating performance on a continuous basis. BP businesses implementing OMS must work to integrate group requirements within their local system to meet legal obligations, address local stakeholder needs, reduce risk and improve efficiency and reliability. A number of mandatory operating and engineering technical requirements have been defined within the OMS, to address process safety and related risks.

All operated businesses plan to transition to OMS by the end of 2010. Eight sites completed the transition to OMS in 2008; two petrochemicals plants, Cooper River and Decatur, two refineries, Lingen and Gelsenkirchen and four Exploration and Production sites, North America Gas, the Gulf of Mexico, Colombia and the Endicott field in Alaska. Implementation is continuing across the group and a number of other sites, including all refineries not already operating the OMS, are expected to complete the transition in 2009.

For the sites already involved, implementing OMS has involved detailed planning, including gap assessments supported by external facilitators. A core aspect of OMS implementation is that each site produces its own local OMS , which takes account of relevant risks at the site and details the site s approach to managing those risks. As part of its transition to OMS, a site issues its local OMS handbook, and this summarizes its approach to risk management. Each site also develops a plan to close gaps that is reviewed annually. The transition to OMS, at local and group level, has been handled in a formal and systematic way, to ensure the change is managed safely and comprehensively.

Performance review

Experience so far has supported our expectation that having one integrated and coherent system brings benefits of simplification and clarity, and that the process of change is supporting our renewed commitment to safe operations.

We are on track to meet our target of implementing OMS across the group by the end of 2010.

Capability development

In addition to ongoing training programmes we are undertaking a group wide programme to enhance the capability of our staff from front line to executive level to deliver operational excellence.

Almost 1,000, around a third, of our front-line supervisors have started the Operating Essentials programme, which includes training on leadership, process safety, operating culture, practices and coaching and effective performance conversations.

More than 190, around half, of our operations leaders started the Operations Academy programme in 2008. The academy, which has been established in partnership with the Massachusetts Institute of Technology (MIT), provides participants with a total of six weeks of operations training, concentrating on the management of change and continuous improvement.

The Executive Operations programme, which seeks to increase insight into manufacturing and operation activities among senior business leaders, has built on its successful launch with the first group, which included the group chief executive and his executive team. By the end of 2008, 99 executives had attended the three-day programme.

In addition, new cadres of projects and engineering staff have progressed through the Project and Engineering Academy at MIT and 13 process safety courses have been delivered for project and project engineering managers at the Project Management College. We have continued to develop training on hazard evaluation and risk assessment techniques for all engineers, operators and HSSE professionals.

Process safety management

We remain fully committed to becoming a recognized industry leader in process safety management and are working to achieve this. We have taken a range of steps, including acting on the recommendations from both the panel and those within the first annual report of the independent expert.

Our actions can be summarized in three principal areas:

We have made progress in reducing process safety risk at our US refineries. For example, we have completed and learned from safety and operations audits, relocated workers to lower-risk accommodation and implemented fatigue reduction programmes.

Executive management has taken a range of actions to demonstrate their leadership and commitment to safety. The group chief executive has consistently emphasized that safety, people, and performance are our top priority, a belief made clear in his 2007 announcement of a forward agenda for simplification and cultural change in BP. Safety performance has been scrutinized by the Group Operations Risk Committee (the GORC), chaired by the group chief executive and tasked with assuring the group chief executive that group operational risks are identified and managed appropriately. We continued to build our team of safety and operations auditors. A team of 45 auditors is now in place, with 36 audits completed in 2008.

Many of the process-safety related improvements recommended by the panel are being implemented across the group through the OMS. The group essentials within the OMS (which cover diverse aspects of operating activity including legal compliance, process and environmental safety and basic operating practices) in some cases go beyond the panel s process safety recommendations, a point noted by the independent expert in his first report.

In addition to action in these areas, we have continued to participate in industry-wide forums on process safety and have made efforts to share our learning with other organizations.

The independent expert has been tasked with reporting to the board on BP s progress in implementing the panel s recommendations. We welcome the independent expert s view expressed in his first report (May 2008) that BP appears to be making substantial progress in changing culture and addressing needed process safety improvements . However, we also acknowledge his observation that a significant amount of work remains to be done on the process safety journey and that successful completion of the task will require the continued support and involvement of the board, executive management, and refinery leadership along with a sustained effort over an extended period of time . The independent expert s second report is expected in the first half of 2009.

Operational integrity

We continue to implement the six-point plan launched in 2006 to address immediate priorities for improving process safety and minimizing risk at our operations worldwide.

We have met our commitment to remove occupied portable buildings (OPBs) from high-risk zones within onshore process plant areas and to remove all blow-down stacks in heavier-than-air, light hydrocarbon service. All major sites and our fuels value chains have completed major accident risk assessments, which identify major accident risks and develop mitigation plans to manage and respond to them.

We continue to implement the Control of Work and Integrity Management standards. We have made progress in ensuring our operations meet the requirements of a group framework designed to ensure we stay in compliance with legal requirements on health and safety. We are continuing to take steps to close out past audit actions. Leadership competency assessments, which involve assessment of the experience of BP management teams responsible for major production sites or manufacturing plant, have been completed in Exploration and Production and in all major Refining and Marketing manufacturing sites.

Implementation of these actions is expected to be largely complete by the end of 2009, with some aspects of implementation being incorporated into the transition to the OMS, expected to be completed by the end of 2010. The GORC regularly monitors progress against the plan.

We monitor and report separately on major incidents such as those covering fatal accidents, significant property damage or significant environmental impact. We also track and analyze high potential incidents those that could have resulted in a major incident. All major incidents and many high-potential incidents are discussed by the GORC and we continue to seek to learn as much as possible from each incident.

A total of 21 major incidents were reported in 2008. Two of the major incidents were related to hurricanes and eight were related to driving incidents.

There were 335 oil spills of one barrel or more in 2008, similar to 2007 performance of 340 oil spills. The volume of oil spilled in 2008 was approximately 3.5 million litres, an increase of 2.5 million litres, compared with 2007. This was largely the result of two incidents, one at Texas City and one at the Whiting refinery, which accounted for two-thirds of the total reported volume of oil spilled, the great majority of which remained contained and the oil recovered.

Performance review

Performance indicators

We have well-developed systems, processes and metrics for reporting personal safety and environmental metrics that support internal performance management as well as public reporting.

We introduced several new metrics in 2008 that aim to enhance our monitoring of process safety performance within BP s operating entities. These include, for example, a process safety incident index, as recommended by the panel, which uses weighted severity scores to record and assess process safety events, and a measure to record any loss of hydrocarbon from primary containment.

Our indicators include industry-aligned lagging process safety metrics that register events that have already occurred, and leading indicators that focus on the strength of our controls to prevent undesired events in future. A suite of indicators is regularly reported to the GORC within the quarterly HSE and Operations Integrity Report and several new metrics have also been piloted. To further enhance the management of health risks across the group, we began the systematic reporting of recordable illness rates within the HSE and Operations Integrity Report. We continue to work with industry bodies such as the Centre for Chemical Process Safety and the American Petroleum Institute on the development of process safety metrics, definitions and guidance.

Continuing to focus on health

In addition to our efforts to improve process safety performance, we strive to protect the personal health and safety of our workforce, recognizing that healthy performance is delivered through healthy people, healthy processes and healthy plant.

In the course of 2008, we defined health group essentials , which specify requirements designed to prevent harm to the health of employees, contractors, visitors and local communities. These were incorporated within the OMS framework. Our health strategy and plan was also refreshed in 2008. Priorities include reducing significant occupational exposure and infectious disease risks, maintaining robust regulatory compliance in product health and safety and addressing the issue of fatigue management raised by the panel by providing training and awareness-raising.

Environment

Regulation and claims

We are subject to extensive international, national, state and local environmental regulations concerning our products, operations and activities. Current and proposed fuel and product specifications, emission controls and climate change programmes under a number of environmental laws will have a significant effect on the production, sale and profitability of many of our products. Environmental laws also require us to remediate the environmental impacts of prior disposal or releases of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various locations where products are, or have been, produced, processed, stored, distributed, sold or disposed of, such as refineries, chemical plants, natural gas processing plants, oil and natural gas fields, service stations, terminals and waste disposal sites. Some of these obligations relate to prior asset sales or closed facilities. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provisions made are considered by management to be sufficient to meet known requirements.

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP s share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group s overall results of operations or financial position or liquidity. See Financial statements Note 37 on page 156 for the amounts provided in respect of environmental remediation and decommissioning.

We are also subject to environmental and common law claims for personal injury and property damage alleging the release or exposure to hazardous substances. A number of proceedings involving governmental authorities are pending or known to be contemplated against BP and certain of its subsidiaries under federal, state or local environmental laws, each of which could result in monetary sanctions of $100,000 or more. No individual proceeding is, nor are the proceedings in aggregate, expected to be material to the group s results of operations or financial position.

We cannot accurately predict the effect of future developments, such as stricter environmental laws or enforcement policies on the group s operations, products or profitability. A risk of increased environmental costs and operational impacts is inherent in grouping our businesses and there can be no assurance that material liabilities and costs will not be incurred in the future. We believe that the group s activities are in material compliance with applicable environmental laws and regulations, or that the group has disclosed such non-compliance and is working with the relevant regulatory authorities to ensure compliance. For a discussion of the group s environmental expenditure see page 53.

BP operates in more than 90 countries worldwide. In each of these areas, BP has, or is developing, processes designed to ensure compliance with applicable regulations. In addition, each employee is required to comply with BP health, safety and environmental policies as embedded in the BP code of conduct. Our partners, suppliers and contractors are also encouraged to adopt them.

This Environment section focuses primarily on the US and the EU, where around 61% of our fixed assets are located, and on issues of a global nature such as our operations and the environment, climate change programmes and maritime oil spills regulations.

Our operations and the environment

During 2008, we continued to use environmental management systems to seek improvements on a wide range of environmental issues. Except at two locations, the operations at our major operating sites are covered

Performance review

by certification to the ISO 14001 international environmental management system standard. The Texas City refinery, after completing planned work to strengthen its environmental management systems, is planning to seek recertification in 2009. Our Angola business is working towards an expansion of its existing ISO 14001 certificate to include its offshore production facilities by the end of 2009. Progressive implementation of the Operating Management System (OMS), including ISO 14001, will also help us strengthen our management of environmental performance.

In support of ongoing risk management, one element of the OMS applies, at least annually, a formal systematic process to identify and assess risks; this process provides to identify emerging issues including those with an environmental impact. To assist us in measuring the effectiveness of our risk mitigation actions we have established environmental metrics, which are available within *BP Sustainability Report 2008*, at *www.bp.com/sustainability*. The 2008 information is planned to be available in conjunction with the publication of our 2008 Sustainability Report.

After two years of implementation, our Environmental Requirements for New Projects (ERNP) practice has been updated in line with the OMS. We have simplified applicability, clarified the governance process and updated the text to reflect organizational changes. This practice, now called the Environmental Group Defined Practice (GDP) is a full life cycle environmental assessment process. It requires all new major projects and projects in sensitive areas, to undertake screening to determine the potential environmental sensitivities associated with the proposed projects. Requirements and project recommendations now extend to include appropriate considerations for decommissioning of assets. A new project with the highest level of environmental sensitivity requires more rigorous and specific environmental management activities. The board-appointed Safety, Environment and Ethics Assurance Committee reviewed the progress of ERNP during summer 2008. This review included the 12 projects that have been classified as requiring management at the highest level of sensitivity. We are currently integrating social considerations into the Environmental GDP and plan to issue this in 2009 as an integrated set of requirements addressing social and environmental issues.

In 2008, BP used the ERNP to review risks and establish mitigation measures prior to entry in connection with the decision to develop adjacent to a Protected Area at Hamble Oil Terminal in the UK. We intend to make a summary of the risk assessment publicly available at the end of April 2009.

Our focus on asset decommissioning is demonstrated by the North West Hutton offshore platform project in the North Sea. 2008 saw the topsides of the North West Hutton platform safely brought onshore for further dismantling. This decommissioning is expected to result in 20,000 tonnes of recycled steel, in line with our aim to have 97% of the decommissioned materials recycled and/or reused.

We seek to limit the environmental impact of our operations by using resources responsibly and reducing waste and emissions.

Climate change programmes

In response to rising concerns about climate change, governments continue to identify fiscal and regulatory measures at local, national and international levels.

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto, Japan, the participants agreed on a system of differentiated international legally-binding targets for the first commitment period of 2008-2012. In 2005, the Kyoto protocol came into force, committing the 176 participating countries to emissions targets. However, Kyoto was only designed as a first step and policymakers continue to discuss what new agreement might follow it after 2012, most recently at the UNFCCC conference in Poznan, Poland in December 2008.

Many of our larger EU stationary assets are subject to the EU Emissions Trading Scheme (EU ETS), which was extended to Norway by reciprocal agreement. After inclusion of our Norwegian assets, around one-fifth of our reported 2008 global CO_2 emissions are now covered by this scheme.

At the March 2007 European Council, the European Heads of Government decided to adopt their Climate Action and Renewable Energy Package. This legislation was voted through by the European Parliament in

December 2008. The package includes a commitment to reduce greenhouse gas (GHG) emissions by 20% by 2020 (the target being 30% if an international agreement is reached), as well as an improved energy efficiency within the EU Member States of 20% by 2020 and a 20% renewable energy target by 2020.

The Australian government has set a target to reduce GHG emissions by 60% below 2000 levels by 2050. In December 2008, the Australian government released its Carbon Pollution Reduction Scheme White Paper, outlining the design of an emissions trading scheme that will go into effect in mid-2010; draft legislation is expected in early 2009. The Australian government proposes to cover 70% of emissions sources and sectors via a combination of direct obligations on facilities with large emissions, and obligations on upstream fuel suppliers for the emissions resulting from the combustion of fuel. In December the government also announced 2020 GHG emission targets that range from a 5 to 15% reduction from 2000 levels. The scheme builds on the existing National Greenhouse and Energy Reporting System, the Australian mandatory reporting system for corporate greenhouse gas emissions and energy production and consumption. The first reporting period commenced on 1 July 2008.

The US congress continues to propose new climate change legislation and regulation. A new bill became law in December 2007, that includes stricter corporate average fuel emissions standards for automobiles sold in the US and biofuel mandates. Other bills currently under consideration propose stricter emissions limits on large GHG sources and/or the introduction of a cap-and-trade programme on CO_2 and other GHG emissions.

An April 2007 US Supreme Court decision will require the US Environmental Protection Agency (EPA) to reconsider its determination that it is not required to regulate GHGs from motor vehicles under the Clean Air Act (CAA). The Supreme Court s ruling is expected to result in the EPA regulating motor vehicle GHG emissions. It is also expected to increase pressure on the EPA to regulate stationary sources of GHGs (e.g. refineries and chemical plants) under other provisions of the CAA.

In response to the US Supreme Court s decision, the EPA issued an Advanced Notice of Proposed Rulemaking (ANPR). The ANPR addresses complexities involved in controlling greenhouse gases under the CAA including potential overlap between future legislation and regulation under the existing CAA.

In its Fiscal Year 2008 Consolidated Appropriations Act, US Congress directed the EPA to publish a mandatory GHG reporting rule, issuing a proposed rule within nine months (by September 2008), and a final rule within 18 months (by June 2009). The EPA has developed draft language and the proposed rule could be released early in the new US administration.

Congress will likely develop new legislation for GHG regulation, and new regulation under the CAA will likely proceed as well. Additional GHG regulation may also be issued under other laws, such as the National Environmental Protection Act (NEPA) and Endangered Species Act (ESA).

In December 2008, the California Air Resources Board (CARB) approved the final Proposed Scoping Plan for implementing Assembly Bill 32, California s law to reduce GHG emissions to 1990 levels by 2020. Implementation measures are due to be developed by 2012. In advance of the Scoping Plan, CARB has taken early actions with the development of mandatory GHG reporting and a Low Carbon Fuel Standard (LCFS). The LCFS will require all refiners, producers, blenders and importers to reduce the carbon intensity of transport fuel sold in California by 10% by 2020. CARB released draft LCFS regulations in October 2008, with final regulations expected to be taken up in March 2009.

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In March 2008, the Canadian federal government updated its April 2007 Framework Report with an Action Plan to address climate change and reduce emissions 20% below 2006 levels by 2020 and by greater than 60% by 2050, through both a sector approach and domestic development and deployment of new technologies and projects. For the conventional oil and gas industry, the intensity based targets as included in the plan of the April 2007 Framework Report remain likely. For the oil sands industry, more stringent requirements are likely to emerge for upcoming projects that may include requirements for significant reductions, including the implementation of large scale carbon capture and sequestration. Since the conclusion of the recent Canadian and US Federal elections there has been increased discussion on the possibility of aligning regulations, including possible inclusion of a North America wide cap-and-trade system.

Since 1997, BP has been actively involved in the policy debate. We also ran a global programme that reduced our operational GHG emissions by 10% between 1998 and 2001. We continue to look at two principal kinds of GHG emissions: operational emissions, which are generated from our operations such as refineries, chemicals plants and production facilities; and product emissions, generated by our customers when they use the fuels and products that we sell. Since 2001, we have been focusing on measuring and improving the carbon intensity of our operations as well as developing sustainable low-carbon technologies and businesses.

After seven years, we estimate that our operations have delivered some 7.5 million tonnes (Mte) of GHG reductions. Our 2008 operational GHG emissions were 61.4Mte of CO2 equivalent on a direct equity basis, nearly 2.1Mte lower than the reported figure of 63.5Mte in 2007. The primary reason for the lower reported emissions is a reporting protocol change for BP Shipping (1.9Mte) to align us more closely with industry practice.

In 2007, as part of our technology development, two major BP-backed research institutes came into full operation: the Energy Biosciences Institute (EBI) in the US, and the Energy Technologies Institute (ETI) in the UK. The EBI is a strategic partnership between BP, the University of California, Berkeley, the Lawrence Berkeley National Laboratory and the University of Illinois, Urbana-Champaign to conduct research into the production of new and cleaner energy, initially focusing on advanced biofuels for road transport. The EBI will also pursue bioscience-based research into the conversion of heavy hydrocarbons to clean fuels, improved recovery from existing oil and gas reservoirs and carbon sequestration. In the UK, the ETI has been established as a 50:50 public private partnership, funded equally by member companies, including BP, and the government. The ETI aims to accelerate the development, demonstration and eventual commercial deployment of a focused portfolio of energy technologies, which will increase energy efficiency, reduce GHG emissions and help achieve energy security and climate change goals. The ETI has issued its first invitation for expressions of interest to participate in programmes to develop new technologies for offshore wind and for marine, tidal and wave energy. BP established the Carbon Mitigation Initiative in 2000 at Princeton University in the US to research the fundamental scientific, environmental, and technological issues that will determine how carbon is managed in the future and examine the policy impact of different options. BP s original 10-year commitment initially funded the programme at $1.5 million per year and later increased it to more than $2 million per year. In October 2008, BP committed to a five-year renewal of the partnership and to support Princeton to at least its current level of funding for the years 2011 to 2015.

Maritime oil spill regulations

Within the US, the Oil Pollution Act of 1990 (OPA 90) imposes oil spill prevention and planning requirements liability for tankers and barges transporting oil and for offshore facilities such as platforms and onshore terminals. To ensure adequate funding for oil spill response and compensation, OPA 90 created the Oil Spill Liability Trust Fund that is

financed by a tax on imported and domestic oil. In 2006, the Coast Guard and Maritime Transportation Act 2006, increased the size of the fund from the original amount of $1 billion to $2.7 billion. In late 2008, as part of the Emergency Economic Stabilization Act, further amendments were made to increase the per-barrel contribution rate of tax and to remove the provision for cessation of the tax when the fund reached $2.7 billion. There is now no limit on the size of the fund. The same 2008 legislation amended the termination date of this tax from 31 December 2014 to 31 December 2017. The 2006 legislation also increased the OPA limitation amount relating to the liability of double-hulled tankers from $1,200 per gross tonne to $1,900 per gross tonne. In addition to the spill liabilities imposed by OPA 90 on the owners and operators of carrying vessels, some states, including Alaska, Washington, Oregon and California, impose additional liability on the shippers or owners of oil spilled from such vessels. The exposure of BP to such liability is mitigated by the vessels marine liability insurance, which has a maximum limit of $1 billion for each accident or occurrence. OPA 90 also provides that all new tank vessels operating in US waters must have double hulls and existing tank vessels without double hulls must be phased out by 2015. At the end of 2008, BP owned four double-hulled tankers built between 2004 and 2006, demise-chartered to and operated by Alaska Tanker Company, L.L.C. (ATC), which transports BP Alaskan crude oil from Valdez.

Outside of US territorial waters, the BP-operated fleet of tankers is subject to international spill response and preparedness regulations that are typically promulgated through the International Maritime Organization (IMO) and implemented by the relevant flag state authorities. The International Convention for the Prevention of Pollution from Ships (Marpol 73/78) requires vessels to have detailed shipboard emergency and spill prevention plans. The International Convention on Oil Pollution, Preparedness, Response and Co-operation requires vessels to have adequate spill response plans and resources for response anywhere the vessel travels. These conventions and separate Marine Environmental Protection Circulars also stipulate the relevant state authorities around the globe that require engagement in the event of a spill. All these requirements together are addressed by the vessel owners in Shipboard Oil Pollution Emergency Plans. BP Shipping s liabilities for oil pollution damage under the OPA 90 and outside the US under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage (CLC) are covered by marine liability insurance, having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by three mutual insurance associations (P&I Clubs): The United Kingdom Steam Ship Assurance Association (Bermuda) Limited; The Britannia Steam Ship Insurance Association Limited; and The Standard Steamship Owners Protection and Indemnity Association (Bermuda) Limited. With effect from 20 February 2006, two new complementary voluntary oil pollution compensation schemes were introduced by tanker owners, supported by their P&I Clubs, with the agreement of the International Oil Pollution Compensation Fund at the IMO. Pursuant to both these schemes, tanker owners will voluntarily assume a greater liability for oil pollution compensation in the event of a spill of persistent oil than is provided for in CLC. The first scheme, the Small Tanker Owners Pollution Indemnification Agreement (STOPIA), provides for a minimum liability of 20 million Special Drawing Rights (around $30 million) for a ship at or below 29,548 gross tonnes, while the second scheme, the Tanker Owners Pollution Indemnification Agreement (TOPIA), provides for the tanker owner to take a 50% stake in the 2003 Supplementary Fund, that is, an additional liability of up to 273.5 million Special Drawing Rights (around $405 million). Both STOPIA and TOPIA will only apply to tankers whose owners are party to these agreements and who have entered their ships with P&I Clubs in the International Group of P&I Clubs, so benefiting from those clubs pooling and reinsurance arrangements. All BP Shipping s managed and time-chartered vessels participate in STOPIA and TOPIA.

For information regarding maritime security issues, see Shipping on page 35.

Performance review

US

The following is a summary of significant US environmental issues and environment and health and safety legislation or regulations affecting BP.

The CAA and its regulations, administered by the United States Environmental Protection Agency (EPA) require, among other things: stringent air emission limits and operating permits for chemicals plants, refineries, marine and distribution terminals and exploration and production facilities, strict fuel specifications and sulphur reductions; enhanced monitoring of major sources of specified pollutants; and risk management plans for storage of hazardous substances. This law affects BP facilities producing, storing, refining, manufacturing and distributing oil and products as well as the fuels themselves. Federal and state controls on ozone, particulate matter, carbon monoxide, benzene, sulphur, MTBE, nitrogen dioxide, oxygenates, lead and Reid Vapor Pressure affect BP s activities and products. Under the CAA all gasoline produced by BP is subject to the EPA s stringent low-sulphur standards. By June 2006, at least 80% of the highway diesel fuel produced each year by BP was required to meet a sulphur cap of 15 parts per million (ppm). By June 2007, all non-road locomotive and marine diesel fuel produced each year by BP was required to meet a sulphur cap of 500ppm. Additionally, states have separate laws similar to the CAA.

The Energy Policy Act of 2005 affects the US fuels market by: eliminating the Federal Reformulated Gasoline (RFG) oxygen requirement in May 2006; establishing a renewable fuels mandate (4 billion gallons in 2006, increasing to 7.5 billion in 2012); consolidating the summertime RFG volatile organic compound (VOC) standards for EPA Regions 1 and 2; allowing the Ozone Transport Commission states on the east coast to opt any area into RFG; and allowing states to repeal the 1psi Reid Vapor Pressure waiver for 10% ethanol blends.

The Energy Independence and Security Act of 2007 increased the renewable fuel mandate to 9 billion gallons in 2008 and further each year to a maximum of 36 billion gallons in 2022.

In 2001, BP entered into a consent decree with the EPA and several states that settled alleged violations of various CAA requirements related largely to emissions of sulphur dioxide and nitrogen oxides at BP s US refineries. Implementation of the decree s requirements continues.

In 2001, BP s US refineries entered into a civil consent decree with the EPA to resolve alleged violations of the CAA. The decree applies to all the US refineries of BP Products North America Inc. (BP Products). On 19 February 2009, the EPA and US Department of Justice (DOJ) lodged an amendment to the 2001 decree. The amendment applies only to the Texas City refinery and resolves alleged violations of both the 2001 decree and the CAA. The decree requires that BP Products pays a $12 million civil fine, funds a $6 million supplemental environmental project and takes steps at the Texas City refinery to enhance compliance with CAA rules.
The estimated cost of these compliance measures is approximately $150 million. The decree amendment is subject to court approval.

The Clean Water Act (CWA) and its regulations, administered by EPA and the US Coast Guard, regulate the discharge of wastewater, stormwater and toxic discharges from BP s onshore and offshore operations to navigable waters. Facilities are required to obtain discharge permits, install control equipment and implement operational controls and preventative measures. Additionally, states have separate laws similar to the CWA.

The Resource Conservation and Recovery Act (RCRA) and its regulations, administered by the EPA, regulate the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes and require the investigation and remediation of locations at a facility where such wastes have been managed. Many BP facilities generate and manage wastes regulated by RCRA and several include locations that are subject to investigation and corrective action. Additionally, states have separate laws similar to RCRA.

Under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund), persons who arranged to dispose of hazardous substances at a site, persons who currently own or operate a site where such substances have been
disposed and certain other parties are strictly liable for the cost of responding to related hazardous substance contamination. EPA administers CERCLA. Additionally, states have separate laws similar to CERCLA.

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA or otherwise named under similar state statutes at approximately 809 sites. A PRP or named party can incur joint and several liability for site remediation costs under some of these statutes and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 50 of these sites. For the remaining sites, BP is one of many potentially responsible parties, and BP expects its share of remediation costs at these sites to be small in comparison with the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP or is otherwise named at a site is approximately $1.7 billion.

BP is also subject to claims for natural resource damages (NRD) under CERCLA, the OPA 90 and other federal and state laws. NRD claims have been asserted by government trustees against a number of BP operations. Many environmental clean-ups are driven by state and federal groundwater protection standards. Contamination or the threat of contamination of current or potential potable (and occasionally non-potable) water resources can result in stringent clean-up requirements. BP has encouraged risk-based approaches to these issues and seeks to tailor remedies at its facilities to match the level of risk presented by the contamination.

Other legislation that significantly affect BP operations includes: the Toxic Substances Control Act, administered by EPA, which regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act, administered by the Occupational Safety and Health Administration, which imposes workplace safety and health, training and process safety requirements to reduce the risks of physical and chemical hazards and injury to employees; the CAA, which created the US Chemical Safety and Hazard Investigation Board which investigates the causes of chemical accidents and makes non-binding recommendations to industry, government and non-governmental organizations; and the Emergency Planning and Community Right-to-Know Act, administered by the EPA, which requires emergency planning and hazardous substance release notification as well as public disclosure of chemical usage and emissions. In addition, the US Department of Transportation (DOT) regulates the transportation of the BP s petroleum products such as crude oil, gasoline and chemicals.

BP is subject to the Marine Transportation Security Act (MTSA) and regulations and the DOT Hazardous Materials (HAZMAT) security compliance regulations. These regulations require many of BP s businesses to conduct security vulnerability assessments and prepare security mitigation plans that require upgrades to security measures, the appointment and training of security personnel and the submission of plans for approval and inspection by government agencies.

The US government through the Department of Homeland Security, in an effort to further mitigate the threat of terrorism to critical US infrastructure, has implemented two new security legislation initiatives, that began in 2007 and has continued through 2008:

Chemical Facility Anti-Terrorism Standard (CFATS).

Transportation Workers Identification Credential (TWIC).

CFATS is intended to provide an enhanced security posture for US facilities that manufacture or store Chemicals of Interest, including gasoline. Additionally, in the future, it will cover facilities that have national economic impact to the US, should these facilities be a target for terrorism. A number of BP facilities may be required to conduct a detailed security vulnerability assessment and a detailed security plan for each facility impacted.

TWIC requires all designated personnel with unescorted access to restricted areas of MTSA designated facilities to submit to a background screening programme and to obtain a biometric identification card. All of

Performance review

BP s MTSA-regulated facilities will be impacted and will be required to comply by the end of 2008 or beginning of 2009 in a phased approach.

The BP Americas Response Team consists of approximately 210 trained emergency responders at BP locations throughout North America. In addition, there are five Regional Response Incident Management Teams, a number of HAZMAT Teams and emergency response teams at BP s major facilities. Collectively, these teams are ready to assist in a response to a major incident.

In 2008, BP Products obtained and renewed environmental permits that enabled it to commence construction on the project to upgrade the Whiting refinery. Various environmental groups have challenged these permits in state and federal proceedings.

In November 2007, the EPA began issuing a series of notices of violations, alleging clean air act violations, to the Whiting, Toledo, Carson and Cherry Point refineries. Settlement negotiations continue between BP Products, the EPA and the DOJ in an effort to resolve these matters. In October 2008, the EPA issued an amended notice of violation alleging that BP Products began construction on the Whiting upgrade in 2005 prior to receiving the necessary permits. This allegation has been incorporated into the permit challenges filed by the environmental groups. The subject matter of the notices of violation could be resolved as an amendment to the 2001 EPA consent decree or as a separate matter.

See also Legal proceedings on page 88.

European Union

The following is a summary of significant EU level environmental legislation and UK health and safety legislation affecting BP.

At the March 2007 European Council, the European Heads of Government decided to adopt:

- a commitment to reduce GHG emissions by at least 20% by 2020 as compared with 1990 levels and the objective of a 30% reduction by 2020, subject to the conclusion of a comprehensive international climate change agreement; and
- a mandatory EU target of 20% renewable energy by 2020 including a 10% biofuels target.

In December 2008, the European Parliament approved the Climate Action and Renewable Energy Package , which:

- revises the EU s Emissions Trading System to establish auctioning of emission allowances from 2013;
- sets binding national targets for each EU member state;
- equips power plants to capture and store CO2 underground;
- sets mandatory national targets for each EU member state with the goal of delivering 20% renewable energy target by 2020; and
- provides for a revised Fuel Quality Directive requiring fuel suppliers to reduce the life cycle emission of the fuels they provide by up to 10% by 2020.

BP was involved at the highest levels in the preparation of the Climate Action and Renewable Energy Package , as part of our efforts to actively contribute to the formulation of energy security and climate change policy in the EU.

An EC directive for a system of integrated pollution prevention and control (IPPC) was adopted in 1996. This system requires certain listed industrial installations, including most activities and processes undertaken by the oil and petrochemicals industry within the EU, to obtain an IPPC permit, which is designed to address an installation s environmental impacts, air emissions, water discharges and waste in a comprehensive and integrated fashion. The permit requires, among other things, the application of Best Available Techniques (BAT), taking into account the costs and benefits, unless an applicable environmental quality standard requires more stringent restrictions, and an assessment of existing environmental impacts and future site closure obligations. All such plants had to obtain such a permit by 30 October 2007 and permits included an environmental improvement programme where necessary.

In December 2007, the EC issued a proposal for the revision to the IPPC Directive with the aims of streamlining legislation on industrial emissions, improving the implementation of BATs across Europe, and contributing to the achievement of the targets set in the EC s Thematic Strategies on Air, Soil and Waste. The proposal merges and revises several separate directives related to industrial emissions (including the Large Combustion Plant Directive) into one Directive. It proposes tighter minimum standards for emissions from large combustion plant (>50MW), and introduces a mandatory requirement to achieve emission limit values indicated by use of Best Available Techniques (with derogations from this requirement allowed where justified).

The proposal would also extend the scope of IPPC to specifically cover organic chemical manufacture by biological treatment (biofuels) and may open the way for NOx and SOx trading by member states.

The EC proposal has triggered considerable debate and the timetable for the completion of the legislative process and the likely outcome are not clear. However, the revision has already triggered a greater focus on the information sharing process that is used to determine and document the BAT for each industry sector, and will raise the profile of the outputs from this process the BAT Reference Documents (BREFs).

In 2005, the EC published its Thematic Strategy on Air Pollution, which outlines EU-wide targets for health and environmental benefits from improved air quality to be achieved through further controls on emissions of fine particulates (PM 2.5 particulate matter less than 2.5 microns diameter), sulphur dioxide, oxides of nitrogen, volatile organic compounds and ammonia. Associated with this is the revision to the National Emissions Ceiling Directive (NECD), which would introduce new emissions ceilings for each member state for fine particles and tighten existing ceilings for sulphur dioxide, oxides of nitrogen, volatile organic compounds and ammonia. There is currently uncertainty regarding the costs to industry of implementing possible outcomes from the NECD and IPPC revisions.

The proposed revision of the current EU Fuel Quality Directive is referred to in the Climate Change Programmes section above. In addition to its provisions regarding life cycle GHG emission reductions, it would also facilitate the introduction of biofuels into gasoline and diesel.

Registration, Evaluation and Authorization of Chemicals (REACH) legislation became effective 1 June 2007 across all member states of the EU. All chemical substances manufactured within, or imported into, the EU in quantities above 1 tonne per annum must be registered fully by each manufacturer/importer with the new European Chemical Agency (ECHA). Failure to comply with REACH in respect of such a substance will immediately remove a company s legal right to manufacture or import that substance. Initially all existing manufactured and imported substances had to be pre-registered by 1 December 2008, to qualify for a timed phase-in for full registration during the period 2010-2018, with the exact timing being determined by the volumes of chemicals manufactured/imported, and by the health, safety and environmental hazards the chemical may possess. Failure to pre-register an existing chemical will result in an immediate requirement to register fully the chemical with the ECHA prior to continued manufacture within, or import into, the EU. Time-limited authorizations may be granted for substances of high concern and in some cases restrictions in use may apply. Crude oil and natural gas are exempt from registration requirements, while fuels are exempt from authorization but not registration. In BP, REACH affects our refining, petrochemicals and other chemical manufacturing operations, with many other businesses, such as lubricants, also being impacted in their roles as major importers and downstream users of chemicals. In 2008, BP submitted around 700 pre-registrations, covering approximately 250 individual chemical substances. For almost 60% of these, full registration dossiers must be submitted to ECHA by 1 December 2010, the balance being required in the period 2013-2018. Total REACH registration fees to be incurred by BP s businesses are estimated to be in the region of $15 million and these contribute to an estimated overall cost of $60 million during the period 2008-2018 for pre-registration, registration and provision of additional testing requirements.

In the UK, significant health and safety legislation affecting BP includes the Health and Safety at Work Act and regulations made thereunder and the Control of Major Accident Hazards Regulations.

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Employees

Number of employees at 31 December	UK	Rest of Europe	US	Rest of World	Total
2008					
Exploration and Production	**3,600**	**700**	**7,700**	**9,400**	**21,400**
Refining and Marketing	**9,000**	**18,000**	**19,000**	**15,500**	**61,500**
Other businesses and corporate	**3,300**	**700**	**2,600**	**2,500**	**9,100**
	15,900	**19,400**	**29,300**	**27,400**	**92,000**
2007					
Exploration and Production	3,800	700	7,800	9,500	21,800
Refining and Marketing	9,700	18,400	22,700	16,400	67,200
Other businesses and corporate[a]	3,500	800	2,500	2,300	9,100
	17,000	19,900	33,000	28,200	98,100
2006					
Exploration and Production	3,600	1,000	7,600	9,200	21,400
Refining and Marketing	10,200	18,600	23,800	15,400	68,000
Other businesses and corporate	3,100	600	2,300	1,600	7,600
	16,900	20,200	33,700	26,200	97,000

[a]A minor amendment has been made to the comparative figure for Rest of the World to correct headcount data.

People and their capabilities are fundamental to our sustainability as a business. To build an enduring business in an increasingly complex and competitive industry, we need people with world-class capabilities, ranging from deepwater drilling and operating refineries to negotiating with governments and planning wind farms.

Our 2008 focus has been on reducing complexity and embedding the performance culture throughout the company. We have implemented structured transformational programmes in a number of strategic performance units (SPUs) and the major functions. We have stopped activity that was being repeated at multiple layers, removed layers of management and have established the SPUs as the principal units of delivery.

There is a greater focus on individual performance management. We have simplified the performance management process and can clearly identify and reward top performing businesses and individuals. Our incentive plans provide a direct link between SPU performance, the individual s contribution, and the bonus outcome.

We had approximately 92,000 employees at 31 December 2008, compared with approximately 98,100 at 31 December 2007.

In managing our people, we seek to attract, develop and retain highly talented individuals in order to maintain BP s capability to deliver our strategy and plans. Our three-year graduate development programme currently has 1,200 participants from all over the world.

We are focusing on the need for deep specialist skills. Accordingly, we have increased external hiring in infrastructure and technical areas. The energy industry faces a shortage of professionals such as petroleum engineers. The number of experienced workers retiring is expected to exceed that of new graduate hires. To help address this issue we are developing more robust resourcing plans supported by initiatives aimed at increasing the numbers of recruits and diversifying the sources from which we recruit. The external hiring initiatives are supported by plans for accelerated discipline development, prioritized deployment and retention schemes.

The continuous improvement we are making to performance management and reward will help ensure that BP meets the expectations of these new recruits who are highly mobile and are more conscious that they have a choice about where to work.

Our policy is to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. Where existing employees become disabled, our policy is to provide continuing employment and training wherever practicable.

In 2008, a global diversity and inclusion (D&I) council was established. This council, chaired by Tony Hayward, is supported by a North American regional council and segment councils. The aim is to harmonize processes and tools for managing D&I across all Segments and Functions. Responsibility for delivering D&I plans sits at the business/SPU level.

The group people committee, formed in 2007, continues to take overall responsibility for policy decisions relating to employees. In 2008, these ranged from senior level talent review and succession planning, embedding of diversity and inclusion plans in the businesses and the structure of long-term incentive plans.

We continue to increase the number of local leaders and employees in our operations so that they reflect the communities in which we operate. For example, in Colombia, national employees now make up 98% of BP s team, while in Azerbaijan, the equivalent proportion is 83%. By 2020, more than half our operations are expected to be in non-OECD countries and we see this as an opportunity to develop a new generation of experts and skilled employees.

At the end of 2008, 14% of our top 583 leaders were female and 19% came from countries other than the UK and the US. When we started tracking the composition of our group leadership in 2000, these percentages were 9% and 14% respectively. We continue to raise our senior level leaders awareness of D&I, and further training is planned in 2009.

We aim to develop our leaders internally, although we recruit outside the group when we do not have specialist skills in-house or when exceptional people are available. In 2008, we appointed 73 people to positions in the group leadership population. Of these, 39 were internal candidates.

We provide development opportunities for our employees, including training courses, international assignments, mentoring, team development days, workshops, seminars and online learning. We encourage all employees to take five training days per year.

A leadership, development and learning steering group was set up in 2008. This body of senior executives has responsibility for guiding and advising on leadership and management development. As part of this, the steering group oversees the Managing Essentials programme, which was successfully rolled out in 2007.

Through our award-winning ShareMatch plan, run in more than 70 countries, we match BP shares purchased by employees.

Performance review

Communications with employees include magazines, intranet sites, DVDs, targeted emails and face-to-face communication. Team meetings are the core of our employee consultation, complemented by formal processes through works councils in parts of Europe. These communications, along with training programmes, are designed to contribute to employee development and motivation by raising awareness of financial, economic, social and environmental factors affecting our performance.

The group seeks to maintain constructive relationships with labour unions.

Pulse surveys conducted in 2008 among samples of employees indicated that BP s safety culture is growing but that overall satisfaction levels have fallen. The surveys also revealed that more work needs to be done to ensure all employees fully understand what they need to do to deliver sustainable high performance.

We continue to make significant efforts to communicate the intent and progress of the forward agenda to reduce the potential negative impacts of this change on the business. We have moved quickly, but our management of change practices keep the focus on safety and ensure that the changes are sustainable. These improvements are expected to continue in 2009, but we have already delivered material reductions in activity, cost and headcount.

The code of conduct

We have a code of conduct designed to ensure that all employees comply with legal requirements and our own standards. The code defines what BP expects of its people in key areas such as safety, workplace behaviour, bribery and corruption and financial integrity. Our employee concerns programme, OpenTalk, enables employees to seek guidance on the code of conduct as well as to report suspected breaches of compliance or other concerns. The number of cases raised through OpenTalk in 2008 was 925, compared with 973 in 2007.

In the US, former US district court judge Stanley Sporkin acts as an ombudsperson. Employees and contractors can contact him confidentially to report any suspected breach of compliance, ethics or the code of conduct, including safety concerns.

We take steps to identify and correct areas of non-compliance and take disciplinary action where appropriate. In 2008, 765 dismissals were reported by BP s businesses for non-compliance or unethical behaviour. This number excludes dismissals of staff employed at our retail service station sites, for incidents such as thefts of small amounts of money.

BP continues to apply a policy that the group will not participate directly in party political activity or make any political contributions, whether in cash or in kind. BP specifically made no donations to UK or other EU political parties or organizations in 2008.

Social and community issues

Contributing to communities

We aim to make a difference in the communities where we operate in a manner that brings benefits to BP as well as the local society. Investment in education, for example, promotes sustainable development as well as providing skilled workers for BP and other companies. Support for local enterprise drives economic growth as well as helping local companies qualify as our suppliers.

BP operates in a diverse range of locations with varying levels of economic and national development. We contribute to communities in ways that are relevant to local circumstances, and which offer opportunities for mutual benefit to our business. Given the scale of our business, our impact often reaches beyond the local community to the national and, in some cases, the international level.

We support education because it creates opportunities for communities, while at the same time providing skills that are critical to BP business and the wider industry. Our interventions in education
are diverse and wide-ranging. We help fund a range of educational programmes, from early years learning to advanced university research, building skills and capability in communities as well advancing knowledge on issues such as climate change and effective economic management of natural resource rich countries. In further and higher education, a major driver for our involvement is the need to encourage more people to develop the particular skills needed for the energy industry. In supporting school education, BP looks to develop children s awareness of links between energy and the environment as well as stimulating interest in science and engineering. In addition to its

investment in the formal learning system, BP supports public education on specific pressing social issues when there is a particular need within a local community.

Through training and financing programmes, BP seeks to support the development of local suppliers by building their skills, sharing internal standards and practice and stimulating business development. This enables greater participation in the supply chain by local business and greater competitiveness overall.

We support several initiatives designed to promote the effectiveness of natural resource led national development. Through the support of the Oxford Centre for the Analysis of Resource Rich Economies, we seek to improve the understanding of the development challenges and policy options available to emerging economies that are rich in natural resources such as oil and gas. We remain a member of the Extractive Industries Transparency Initiative (EITI), which supports the creation of a standardized process for transparent reporting of company payments and government revenues from oil, gas and mining.

In the US, amongst various other initiatives in 2008, we provided more than $17 million to assist with relief and recovery efforts for the wider community following Hurricanes Ike and Gustav in the Gulf of Mexico.

We make direct contributions to communities through community programmes. Our total contribution in 2008 was $125.6 million. This included $0.2 million contributed by BP to UK charities. The growing focus of this is on education, the development of local enterprise and providing access to energy in remote locations.

In 2008, we spent $59.5 million promoting education, with investment in three broad areas: energy and the environment; business leadership skills; and basic education in developing countries where we operate large projects.

Essential contracts

BP has contractual and other arrangements with numerous third parties in support of its business activities. This report does not contain information about any of these third parties as none of our arrangements with them are considered to be essential to the business of BP.

Property, plants and equipment

BP has freehold and leasehold interests in real estate in numerous countries, but no individual property is significant to the group as a whole. See Exploration and Production on page 13 for a description of the group s significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this section.

Organizational structure

The significant subsidiaries of the group at 31 December 2008 and to the group percentage of ordinary share capital (to the nearest whole number) are set out in Financial statements Note 46 on page 173. See Financial statements Notes 26 and 27 on pages 138 and 139 respectively for information on significant jointly controlled entities and associates of the group.

Performance review

Financial and operating performance
Group operating results
The following summarizes the group s operating results.

	$ million except per share amounts		
	2008	2007	2006
Total revenues[a]	**365,700**	288,951	270,602
Profit from continuing operations[a]	**21,666**	21,169	22,626
Profit for the year	**21,666**	21,169	22,601
Profit for the year attributable to BP shareholders	**21,157**	20,845	22,315
Profit attributable to BP shareholders per ordinary share cents	**112.59**	108.76	111.41
Dividends paid per ordinary share cents	**55.05**	42.30	38.40

[a] Excludes Innovene, which was treated as a discontinued operation in accordance with IFRS 5 Non-current Assets Held for Sale and Discontinued Operations in 2004, 2005 and 2006.

Business environment

Crude oil prices reached new record highs in 2008, in nominal terms. The average dated Brent price for the year rose to $97.26 per barrel, an increase of 34% over the $72.39 per barrel average seen in 2007. Daily prices began the year at $96.02 per barrel, peaked at $144.22 per barrel on 3 July 2008, and fell to $36.55 per barrel at year-end. The sharp drop in prices was due to falling demand in the second half of the year, caused by the OECD falling into recession and the lagged effect on demand of high prices in the first half of the year. OPEC had increased production significantly through the first three quarters; and, as a result of falling consumption and rising OPEC production, inventories rose. As prices continued to decline, OPEC responded with successive announcements of production cuts in September, October, and December.

Natural gas prices in the US and the UK increased in 2008. The Henry Hub First of Month Index averaged $9.04/mmBtu, 32% higher than the 2007 average of $6.86/mmBtu. Prices peaked at $13.11/mmBtu in July amid robust demand and falling US gas imports, but fell to $6.90/mmBtu in December as demand weakened and production remained strong. Average UK gas prices rose to 58.12 pence per therm at the National Balancing Point in 2008, 94% above the 2007 average of 29.95 pence per therm.

Refining margins fell back in 2008, with the BP Global Indicator Margin (GIM) averaging $6.50 per barrel. The premium for light products above fuel oils remained high, reflecting a continuing shortage of upgrading capacity and the favouring of fully upgraded refineries over less complex sites.

The retail environment continued to be extremely competitive in 2008 with market volatility, high absolute prices, as well as large price shifts in the crude market.

In 2007, the average dated Brent price rose to $72.39 per barrel, an increase of 11% over the $65.14 per barrel average seen in 2006. Daily prices began the year at $58.62 per barrel and rose to $96.02 per barrel at year-end due to OPEC production cuts in early 2007, sustained consumption growth and a resulting drop in commercial inventories after the summer.

Natural gas prices in the US and the UK declined in 2007. The Henry Hub First of Month Index averaged $6.86/mmBtu, 5% lower than the 2006 average of $7.24/mmBtu. Prices were pressured by strong LNG imports in summer, continued domestic production growth and high inventories. Average UK gas prices fell to 29.95 pence per therm at the National Balancing Point in 2007, 29% below the 2006 average of 42.19 pence per therm.

Refining margins had reached a new record high in 2007, with the BP Global Indicator Margin (GIM) averaging $9.94 per barrel. The premium for light products above fuel oils remained exceptionally high, reflecting a shortage of upgrading capacity and the favouring of fully upgraded refineries over less complex sites.

Hydrocarbon production

Our total hydrocarbon production during 2008 averaged 2,517mboe/d for subsidiaries and 1,321mboe/d for equity accounted-entities, a decrease of 1.2% (a decrease of 3.1% for liquids and an increase of 0.7% for gas) and an increase of 4.0% (an increase of 2.5% for liquids and an increase of 14.8% for gas) respectively compared with 2007. In aggregate, after adjusting for the effect of lower entitlement in our PSAs, production was 5% higher than 2007. This reflected strong performance from our existing assets, the continued ramp-up of production following the startup of major projects in late-2007 and a further nine major project startups in 2008. Our total hydrocarbon production during 2007 averaged 2,549mboe/d for subsidiaries and 1,269mboe/d for equity-accounted entities, a decrease of 3% (3.5% for liquids and 2.6% for gas) and 2% (1.3% for liquids and 8.4% for gas) respectively compared with 2006. In aggregate, the decrease primarily reflected the effect of disposals and net entitlement reductions in our PSAs.

Profit attributable to BP shareholders

Profit attributable to BP shareholders for the year ended 31 December 2008 was $21,157 million, including inventory holding losses, net of tax, of $4,436 million and a net charge for non-operating items, after tax, of $796 million. In addition, fair value accounting effects had a favourable impact, net of tax, of $146 million relative to management s measure of performance. Inventory holdings gains or losses, net of tax, are described in footnote (a) on the following page. Further information on non-operating items and fair value accounting effects can be found on page 51.

Profit attributable to BP shareholders for the year ended 31 December 2007 was $20,845 million, including inventory holding gains, net of tax, of $2,475 million and a net charge for non-operating items, after tax, of $373 million (*see page 52*). In addition, fair value accounting effects had an unfavourable impact, net of tax, of $198 million (*see page 52*) relative to management s measure of performance.

Profit attributable to BP shareholders for the year ended 31 December 2006 was $22,315 million, including inventory holding losses, net of tax, of $222 million and a net credit for non-operating items, after tax, of $1,531 million (*see page 52*). In addition, fair value accounting effects had a favourable impact, net of tax, of $72 million (*see page 52*) relative to management s measure of performance. The profit attributable to BP shareholders for the year ended 31 December 2006 included a loss from Innovene operations of $25 million.

Performance review

The primary additional factors reflected in profit for 2008, compared with 2007, were higher realizations, a higher contribution from the gas marketing and trading business, improved oil supply and trading performance, improved marketing performance and strong cost management; however, these positive effects were partly offset by weaker refining margins, particularly in the US, higher production taxes, higher depreciation, and adverse foreign exchange impacts.

The primary additional factors reflected in profit for 2007, compared with 2006, were higher liquids realizations, stronger refining and marketing margins and improved NGLs performance; however, these were more than offset by lower gas realizations, lower reported production volumes, higher production taxes in Alaska, higher costs (primarily reflecting the impact of sector-specific inflation and higher integrity spend), the impact of outages and recommissioning costs at the Texas City and Whiting refineries, reduced supply optimization benefits and a lower contribution from the marketing and trading business.

Profits and margins for the group and for individual business segments can vary significantly from period to period as a result of changes in such factors as oil prices, natural gas prices and refining margins. Accordingly, the results for the current and prior periods do not necessarily reflect trends, nor do they provide indicators of results for future periods.

Employee numbers were approximately 92,000 at 31 December 2008, 98,100 at 31 December 2007 and 97,000 at 31 December 2006.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies incurred during the year and the cost of sales calculated on the first-in first-out (FIFO) method including any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on the historic cost of acquisition or manufacture rather than the current replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement on a FIFO basis (and any related movements in net realizable value provisions) and the charge that would arise using average cost of supplies incurred during the period. For this purpose, average cost of supplies incurred during the period is calculated by dividing the total cost of inventory purchased in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

Management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP s management believes it is helpful to disclose this information.

Capital expenditure and acquisitions

			$ million
	2008	2007	2006
Exploration and Production	**22,026**	13,904	13,209
Refining and Marketing	**4,710**	4,356	3,105
Other businesses and corporate	**1,450**	934	596

Capital expenditure	**28,186**	19,194	16,910
Acquisitions and asset exchanges	**2,514**	1,447	321
	30,700	20,641	17,231
Disposals	**(929)**	(4,267)	(6,254)
Net investment	**29,771**	16,374	10,977

Capital expenditure and acquisitions in 2008, 2007 and 2006 amounted to $30,700 million, $20,641 million and $17,231 million respectively. In 2008, this included $4,731 million in respect of our transaction with Husky Energy Inc. and $3,667 million in respect of our purchase of all Chesapeake Energy Corporation s interest in the Arkoma Basin Woodford Shale assets and the purchase of a 25% interest in Chesapeake s Fayetteville Shale assets. Acquisitions in 2007 included the remaining 31% of the Rotterdam (Nerefco) refinery from Chevron s Netherlands manufacturing company.

Excluding acquisitions and asset exchanges, capital expenditure for 2008 was $28,186 million compared with $19,194 million in 2007 and $16,910 million in 2006. In 2006, this included $1 billion in respect of our investment in Rosneft.

Finance costs and net finance income relating to pensions and other post-retirement benefits

Finance costs comprises group interest less amounts capitalized, and interest accretion on provisions and long-term other payables. Finance costs for continuing operations in 2008 were $1,547 million compared with $1,393 million in 2007 and $986 million in 2006. The increase in 2008, when compared with 2007, is largely the outcome of reductions in capitalized interest as capital construction projects concluded. The increase in 2007, when compared with 2006, reflected a higher average gross debt balance and lower capitalized interest as capital construction projects concluded.

Net finance income relating to pensions and other post-retirement benefits in 2008 was $591 million compared with $652 million in 2007 and $470 million in 2006. The expected return on assets has increased year on year as the pension asset base applicable to each year increased, but this has been offset in 2008 by higher interest costs reflecting the increase in discount rates applied to pension plan liabilities.

Taxation

The charge for corporate taxes for continuing operations in 2008 was $12,617 million, compared with $10,442 million in 2007 and $12,516 million in 2006. The effective rate was 37% in 2008, 33% in 2007 and 36% in 2006. The group earns income in many countries and, on average, pays taxes at rates higher than the UK statutory rate of 28% for 2008. The increase in the effective rate in 2008 compared with 2007 primarily reflects the change in the country mix of the group s income, resulting in a higher overall tax burden. The reduction in the effective rate in 2007 compared with 2006 primarily reflects the reduction in the UK tax rate and the fact that a higher proportion of income arose in countries bearing a lower tax rate and other factors.

Business results

Profit before interest and taxation from continuing operations, which is before finance costs, other finance expense, taxation and minority interests, was $35,239 million in 2008, $32,352 million in 2007 and $35,658 million in 2006.

Performance review

Exploration and Production

For the year ended 31 December			$ million
	2008	2007	2006
Total revenues[a]	**89,902**	69,376	71,868
Profit before interest and tax from continuing operations[b]	**37,915**	27,729	30,953
Results include:			
Exploration expense	**882**	756	1,045
Of which: Exploration expenditure written off	**385**	347	624

			$ per barrel
Key statistics			
Average BP crude oil realizations[c]			
UK	**92.09**	70.36	62.45
US	**97.37**	68.51	62.03
Rest of World	**94.74**	70.86	61.11
BP average	**95.43**	69.98	61.91
Average BP NGL realizations[c]			
UK	**57.24**	52.71	47.21
US	**52.14**	44.59	36.13
Rest of World	**50.84**	48.14	36.03
BP average	**52.30**	46.20	37.17
Average BP liquids realizations[c d]			
UK	**89.82**	69.17	61.67
US	**89.22**	64.18	57.25
Rest of World	**91.05**	69.56	59.54
BP average	**90.20**	67.45	59.23

			$ per thousand cubic feet
Average BP natural gas realizations[c]			
UK	**8.41**	6.40	6.33
US	**6.77**	5.43	5.74
Rest of World	**5.19**	3.71	3.70
BP average	**6.00**	4.53	4.72

			$ per barrel
Average West Texas Intermediate oil price	**100.06**	72.20	66.02
Alaska North Slope US West Coast	**98.86**	71.68	63.57

Average Brent oil price	**97.26**	72.39	65.14
	$ per million British thermal units		
Average Henry Hub gas price[e]	**9.04**	6.86	7.24
	pence per therm		
Average UK National Balancing Point gas price	**58.12**	29.95	42.19
	thousand barrels per day		
Total liquids production for subsidiaries[d f]	**1,263**	1,304	1,351
Total liquids production for equity-accounted entities[d f]	**1,138**	1,110	1,124
	million cubic feet per day		
Natural gas production for subsidiaries[f]	**7,277**	7,222	7,412
Natural gas production for equity-accounted entities[f]	**1,057**	921	1,005
	thousand barrels of oil equivalent per day		
Total production for subsidiaries[f g]	**2,517**	2,549	2,629
Total production for equity-accounted entities[f g]	**1,321**	1,269	1,297

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

[c]Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

[d]Crude oil and natural gas liquids.

[e]Henry Hub First of Month Index.

[f]Net of royalties.

[g]Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cu

Performance review

Total revenues are analysed in more detail below.

			$ million
	2008	2007	2006
Sales and other operating revenues	**86,170**	65,740	67,950
Earnings from equity-accounted entities (after interest and tax), interest and other revenues	**3,732**	3,636	3,918
	89,902	69,376	71,868

Total revenues for 2008 were $90 billion, compared with $69 billion in 2007 and $72 billion in 2006. The increase in 2008 primarily reflected higher oil and gas realizations. Gas marketing sales also increased primarily as a result of higher prices. The decrease in 2007 compared with 2006 primarily reflected lower volumes of subsidiaries and lower gas marketing sales, partly offset by higher realizations.

Profit before interest and tax for the year ended 31 December 2008 was $37,915 million. This included inventory holding losses of $393 million and a net charge for non-operating items of $990 million (*see page 52*), with the most significant items being net impairment charges (primarily driven by the current low price environment) and net fair value losses on embedded derivatives, partly offset by the reversal of certain provisions. The impairment charge includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year. In addition, fair value accounting effects had an unfavourable impact of $282 million relative to management s measure of performance (*see page 52*).

Profit before interest and tax for the year ended 31 December 2007 was $27,729 million. This included inventory holding gains of $127 million and a net credit from non-operating items of $491 million (*see page 52*), with the most significant items being net gains from the sale of assets (primarily from the disposal of our production and gas infrastructure in the Netherlands, our interests in non-core Permian assets in the US and our interests in the Entrada field in the Gulf of Mexico), partly offset by a restructuring charge and a charge in respect of the reassessment of certain provisions. In addition, fair value accounting effects had a favourable impact of $48 million relative to management s measure of performance (*see page 52*).

Profit before interest and tax for the year ended 31 December 2006 was $30,953 million. This included inventory holding losses of $73 million and a net credit from non-operating items of $2,563 million (*see page 52*), with the most significant items being net gains from the sale of assets (primarily from the sales of interests in the Shenzi discovery in the Gulf of Mexico in the US and interests in the North Sea partly offset by a loss on the sale of properties in the Gulf of Mexico Shelf) and net fair value gains on embedded derivatives, partly offset by a charge for legal provisions. In addition, fair value accounting effects had an unfavourable impact of $32 million relative to management s measure of performance (*see page 52*).

The primary additional factor contributing to the 37% increase in profit before interest and tax for the year ended 31 December 2008 compared with the year ended 31 December 2007 was higher realizations. In addition, the result reflected a higher contribution from the gas marketing and trading business but was impacted by higher production taxes and higher depreciation. The impact of inflation within other costs was mitigated by rigorous cost control and a focus on simplification and efficiency.

The primary additional factors reflected in profit before interest and tax for the year ended 31 December 2007 compared with the year ended 31 December 2006 were higher overall realizations (liquids realizations were higher and gas realizations were lower) and a favourable effect from lagged tax reference prices in TNK-BP; however, these factors were more than offset by the impact of lower reported volumes, a lower contribution from the gas marketing and trading business, higher production taxes in Alaska and higher costs, reflecting the impacts of sector-specific inflation, increased integrity spend and higher depreciation charges. Additionally, the result was lower due to the absence of disposal gains in 2006 in equity-accounted entities.

Reported production for 2008 was 2,517mboe/d for subsidiaries and 1,321mboe/d for equity-accounted entities, compared with 2,549mboe/d and 1,269mboe/d respectively in 2007. In aggregate, after adjusting for the effect of lower entitlement in our PSAs, production was 5% higher than 2007. This reflected strong performance from our existing assets, the continued ramp-up of production following the startup of major projects in late-2007 and the start-up of a further nine major projects in 2008.

Reported production for 2007 was 2,549mboe/d for subsidiaries and 1,269mboe/d for equity-accounted entities, compared with 2,629mboe/d and 1,297mboe/d respectively in 2006. In aggregate, the decrease primarily reflected the effect of disposals and net entitlement reductions in our PSAs.

Performance review

Refining and Marketing

			$ million
	2008	2007	2006
Total revenues[a]	**320,458**	250,897	232,833
Profit before interest and tax from continuing operations[b]	**(1,884)**	6,076	5,419

			$ per barrel
Global Indicator Refining Margin (GIM)[c]			
Northwest Europe	**6.72**	4.99	3.92
US Gulf Coast	**6.78**	13.48	12.00
Midwest	**5.17**	12.81	9.14
US West Coast	**7.42**	15.05	14.84
Singapore	**6.30**	5.29	4.22
BP average	**6.50**	9.94	8.39

			%
Refining availability[d]	**88.8**	82.9	82.5

			thousand barrels per day
Refinery throughputs	**2,155**	2,127	2,198

[a]Includes sales between businesses.

[b]Includes profit after interest and tax of equity-accounted entities.

[c]The GIM is the average of regional industry indicator margins that we weight for BP s crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. The refining margins are industry-specific rather than BP-specific measures, which we believe are useful to investors in analyzing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP s other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP s particular refining configurations and crude and product slate.

[d]Refining availability represents Solomon Associates operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory maintenance downtime.
Total revenues are explained in more detail below.

			$ million
	2008	2007	2006
Sale of crude oil through spot and term contracts	**54,901**	43,004	38,577
Marketing, spot and term sales of refined products	**248,561**	194,979	177,995
Other sales and operating revenues	**16,577**	12,238	15,814
Earnings from equity-accounted entities (after interest and tax), interest, and other revenues	**419**	676	447
	320,458	250,897	232,833

			thousand barrels per day
Sale of crude oil through spot and term contracts	**1,689**	1,885	2,110
Marketing, spot and term sales of refined products	**5,698**	5,624	5,801

Total revenues for 2008 were $320 billion, compared with $251 billion in 2007 and $233 billion in 2006. The increase in 2008 compared with 2007 primarily reflected an increase in marketing, spot and term sales of refined products, mainly driven by higher prices. Additionally, sales of crude oil, spot and term contracts increased, as a result of higher prices, partly offset by lower volumes. The increase in 2007 compared with 2006 was principally due to an increase in marketing, spot and term sales of refined products. This was due to higher prices and a positive foreign exchange impact due to a weaker dollar, partially offset by lower volumes. Additionally, sales of crude oil, spot and term contracts increased, primarily reflecting higher prices, and other sales decreased due to lower volumes partially offset by a positive foreign exchange impact.

The loss before interest and tax for the year ended 31 December 2008 was $1,884 million. This included inventory holding losses of $6,060 million and a net credit for non-operating items of $347 million (*see page 52*). The most significant non-operating items were net gains on disposal (primarily in respect of the gain recognized on the contribution of the Toledo refinery into a joint venture with Husky Energy Inc.) partly offset by restructuring charges. In addition, fair value accounting effects had a favourable impact of $511 million relative to management s measure of performance (*see page 52*).

Profit before interest and tax for the year ended 31 December 2007 was $6,076 million. This included inventory holding gains of $3,455 million and a net charge for non-operating items of $952 million (*see page 52*).
The most significant non-operating items were net disposal gains (primarily related to the sale of BP s Coryton refinery in the UK, its interest in the West Texas pipeline system in the US and its interest in the Samsung Petrochemical Company in South Korea), net impairment charges (primarily related to the sale of the majority of our US Convenience Retail business, a write-down of certain assets at our Hull site and write-down of our retail assets in Mexico) and a charge related to the March 2005 Texas City refinery incident. In addition, fair value accounting effects had an unfavourable impact of $357 million relative to management s measure of performance (*see page 52*).

Profit before interest and tax for the year ended 31 December 2006 was $5,419 million. This included inventory holding losses of $242 million and a net credit for non-operating items of $113 million (*see page 52*). The most significant non-operating items were net disposal gains (related primarily to the sale of BP s Czech Republic retail business, the disposal of BP s shareholding in Zhenhai Refining and Chemicals Company, the sale of BP s shareholding in Eiffage, the French-based construction company, and pipelines assets) and a charge related to the March 2005 Texas City refinery incident. In addition, fair

Performance review

value accounting effects had a favourable impact of $211 million relative to management s measure of performance (*see page 52*).

During 2008, significant performance improvements in both our Fuels Value Chains and International Businesses mitigated cost inflation and, to a large extent, the much weaker environment. The main sources of improvement were from restoring the revenues of our refining operations; improved supply and trading performance; improved marketing performance, particularly from the International Businesses, and reduced costs. The cost reductions have been driven by the simplification of our business structure through the establishment of Fuels Value Chains and a reduction in our geographical footprint, as well as by strong cost management. The most significant environmental factor was the weaker refining environment, particularly due to lower refining margins in the US and the adverse impact in the second half of 2008 of prior-month pricing of domestic pipeline barrels for our US refining system, but there were also adverse foreign exchange effects.

During 2007, the segment continued to focus on the restoration of operations at the Texas City refinery and on investments in integrity management throughout our refining portfolio. We have also focused on the repair and recommissioning of the Whiting refinery following the operational issues in March 2007. In many parts of the refining portfolio and the other market-facing businesses, we delivered high reliability and improved results compared with 2006. However, for the full year, compared with 2006, the impact of the outages and recommissioning costs at the Texas City and Whiting refineries, as well as investments in integrity management and scheduled turnarounds throughout our refining portfolio, cost inflation and lower results from supply optimization decreased our result. These factors more than offset increased margins in both refining and marketing.

The average refining Global Indicator Margin (GIM) in 2008 was lower than in 2007.

Refining throughputs in 2008 were 2,155mb/d, 28mb/d higher than in 2007. Refining availability was 88.8%, six percentage points higher than in 2007, the increase being driven primarily by improvement at the Texas City and Whiting refineries. Marketing volumes at 3,711mb/d were around 2.5% lower than in 2007.

Other businesses and corporate

			$ million
	2008	2007	2006
Total revenues[a]	**5,040**	3,972	3,703
Profit (loss) before interest and tax from continuing operations[b]	**(1,258)**	(1,233)	(779)

[a] Includes sales between businesses.

[b] Includes profit after interest and tax of equity-accounted entities.

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which includes all the group s cash, cash equivalents), and corporate activities worldwide.

The loss before interest and tax for the year ended 31 December 2008 was $1,258 million and included inventory holding losses of $35 million and a net charge for non-operating items of $633 million (*see page 52*).

The loss before interest and tax for the year ended 31 December 2007 was $1,233 million and included inventory holding losses of $24 million and a net charge for non-operating items of $262 million (*see page 52*).

The loss before interest and tax for the year ended 31 December 2006 was $779 million and included inventory holding gains of $62 million and a net charge for non-operating items of $72 million (*see page 52*).

Non-operating items

Non-operating items are charges and credits that BP discloses separately because it considers such disclosures to be meaningful and relevant to
investors. The main categories of non-operating items in the periods presented are: impairments; gains or losses on sale of fixed assets and the sale of businesses; environmental remediation; restructuring, integration and rationalization costs; and changes in the fair value of embedded derivatives. These disclosures are provided in order to enable investors better to understand and evaluate the group s financial performance. An analysis of non-operating items is shown on page 52.

Non-GAAP information on fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products as well as certain contracts to supply physical volumes at future dates. Under IFRS, these inventories and contracts are recorded at historic cost and on an accruals basis respectively. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories and contracts are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

IFRS requires that inventory held for trading be recorded at its fair value using period end spot prices whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

BP enters into contracts for pipelines and storage capacity that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference by comparing the IFRS result with management s internal measure of performance, under which the inventory and the supply and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. We believe that disclosing management s estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management s internal measure of performance, are shown in the table below and on the following page.

Reconciliation of non-GAAP information

Exploration and Production

			$ million
	2008	2007	2006
Profit before interest and tax adjusted for fair value accounting effects	**38,197**	27,681	39,985
Impact of fair value accounting effects	**(282)**	48	(32)
Profit before interest and tax	**37,915**	27,729	39,953

Refining and Marketing

Profit before interest and tax adjusted for fair value accounting effects	**(2,395)**	6,433	5,208
Impact of fair value accounting effects	**511**	(357)	211

Profit before interest and tax	**(1,884)**	6,076	5,419

Performance review

Non-operating items

	2008	2007	2006
			$ million
Exploration and Production			
Impairment and gain (loss) on sale of businesses and fixed assets	**(1,015)**	857	2,410
Environmental and other provisions	**(12)**	(12)	(17)
Restructuring, integration and rationalization costs	**(57)**	(186)	
Fair value gain (loss) on embedded derivatives	**(163)**		603
Other	**257**	(168)	(433)
	(990)	491	2,563
Refining and Marketing			
Impairment and gain (loss) on sale of businesses and fixed assets	**801**	(35)	726
Environmental and other provisions	**(64)**	(138)	(33)
Restructuring, integration and rationalization costs	**(447)**	(118)	
Fair value gain (loss) on embedded derivatives	**57**		
Other		(661)	(580)
	347	(952)	113
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets	**(166)**	(14)	29
Environmental and other provisions	**(117)**	(35)	94
Restructuring, integration and rationalization costs	**(254)**	(34)	
Fair value gain (loss) on embedded derivatives	**(5)**	(7)	5
Other	**(91)**	(172)	(200)
	(633)	(262)	(72)
Total before taxation for continuing operations	**(1,276)**	(723)	2,604
Taxation[a]	**480**	350	(1,073)
Total after taxation for continuing operations	**(796)**	(373)	1,531

Fair value accounting effects

	2008	2007	2006
			$ million

Exploration and Production			
Unrecognized gains (losses) brought forward from previous period	**107**	155	123
Unrecognized (gains) losses carried forward	**(389)**	(107)	(155)
Favourable (unfavourable) impact relative to management s measure of performance	**(282)**	48	(32)
Refining and Marketing			
Unrecognized gains (losses) brought forward from previous period	**429**	72	283
Unrecognized (gains) losses carried forward	**82**	(429)	(72)
Favourable (unfavourable) impact relative to management s measure of performance	**511**	(357)	211
	229	(309)	179
Taxation[a]	**(83)**	111	(107)
	146	(198)	72
By region			
Exploration and Production			
UK	**45**	1	63
Rest of Europe			
US	**(231)**	(77)	(59)
Rest of World	**(96)**	124	(36)
	(282)	48	(32)
Refining and Marketing			
UK	**186**	(52)	109
Rest of Europe	**54**	(110)	101
US	**231**	(165)	13
Rest of World	**40**	(30)	(12)
	511	(357)	211

[a]The amounts shown for taxation are based upon the effective tax rate on group profit.

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Performance review

			$ million
	2008	2007	2006
Environmental expenditure			
Operating expenditure	**755**	662	596
Clean-ups	**64**	62	59
Capital expenditure	**1,104**	1,033	806
Additions to environmental remediation provision	**270**	373	423
Additions to decommissioning provision	**326**	1,163	2,142

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $755 million in 2008 was higher than in 2007 and reflects continuing integrity management activity. There were no individually significant factors driving the increase.

The increase in environmental operating expenditure in 2007 compared with 2006 is primarily due to increased integrity management activity and activity associated with the implementation of the Baker Panel recommendations. Similar levels of operating and capital expenditures are expected in the foreseeable future. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions is normally in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2008 includes $234 million resulting from a reassessment of existing site obligations and $36 million in respect of provisions for new sites.

Provisions for environmental remediation are made when a cleanup is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environment restoration, remediation and abatement programmes are often inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP s share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group s overall results of operations or financial position.

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility a provision is established that represents the discounted value of the expected future cost of decommissioning the asset. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. The level of increase in the decommissioning provision varies with the number of new fields coming onstream in a particular year and the outcome of the periodic reviews.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by IAS 37 Provisions, Contingent Liabilities and Contingent Assets .

Further details of decommissioning and environmental provisions appear in Financial statements - Note 37 on page 156. See also Environment on page 39.

Suppliers and contractors

Our processes are designed to enable us to choose suppliers carefully on merit, avoiding conflicts of interest and inappropriate gifts and entertainment. We expect suppliers to comply with legal requirements and we seek to do business with suppliers who act in line with BP s commitments to compliance and ethics, as outlined in the code of conduct. We engage with suppliers in a variety of ways, including performance review meetings to identify mutually advantageous ways to improve performance.

Creditor payment policy and practice

Statutory regulations issued under the UK Companies Act 1985 require companies to make a statement of their policy and practice in respect of the payment of trade creditors. In view of the international nature of the group s operations there is no specific group-wide policy in respect of payments to suppliers. Relationships with suppliers are, however, governed by the group s policy commitment to long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment.

Performance review

Liquidity and capital resources

Cash flow

The following table summarizes the group s cash flows.

			$ million
	2008	2007	2006
Net cash provided by operating activities	**38,095**	24,709	28,172
Net cash used in investing activities	**(22,767)**	(14,837)	(9,518)
Net cash used in financing activities	**(10,509)**	(9,035)	(19,071)
Currency translation differences relating to cash and cash equivalents	**(184)**	135	47
Increase (decrease) in cash and cash equivalents	**4,635**	972	(370)
Cash and cash equivalents at beginning of year	**3,562**	2,590	2,960
Cash and cash equivalents at end of year	**8,197**	3,562	2,590

Net cash provided by operating activities for the year ended 31 December 2008 was $38,095 million compared with $24,709 million for the equivalent period of 2007 reflecting a decrease in working capital requirements of $11,250 million, an increase in profit before taxation of $2,672 million and an increase in dividends from jointly controlled entities and associates of $1,255 million; these were partly offset by an increase in income taxes paid of $3,752 million.

Net cash provided by operating activities for the year ended 31 December 2007 was $24,709 million, compared with $28,172 million for the equivalent period for 2006 reflecting an increase in working capital requirements of $6,282 million, a decrease in profit before taxation from continuing operations of $3,531 million, a decrease in dividends from jointly controlled entities and associates of $2,022 million; these were partially offset by a decrease in income taxes paid of $4,661 million, a lower net credit for impairment and gains and losses on sale of businesses and fixed assets of $2,357 million and higher depreciation, depletion and amortization of $1,451 million.

Net cash used in investing activities was $22,767 million in 2008, compared with $14,837 million and $9,518 million in 2007 and 2006. The increase in 2008 reflected a reduction in disposal proceeds of $3,338 million and an increase in capital expenditure of $5,303 million. The increase in 2007 reflected a reduction in disposal proceeds of $1,987 million and an increase in capital expenditure of $2,713 million.

Net cash used in financing activities was $10,509 million in 2008 compared with $9,035 million in 2007 and $19,071 million in 2006. The increase in 2008 reflects a decrease in short-term debt of $2,809 million and an increase in dividends paid of $2,434 million; these were partly offset by a $4,546 million decrease in the net repurchase of shares. The reduction in 2007 compared with 2006 reflects a reduction in net repurchases of shares of $8,038 million and an increase in proceeds from long-term financing of $4,278 million; these were partially offset by a net decrease in short-term debt of $2,379 million.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $23.7 billion in 2008, $18.4 billion in 2007 and $15.7 billion in 2006. Sources of funding are completely fungible, but the majority of the group s funding requirements for new investment come from cash generated by existing operations. The group s level of net debt, that is debt less cash and cash equivalents, was $25.0 billion at the end of 2008, $26.8 billion at the end of 2007 and was $21.1 billion at the end of 2006.

During the period 2006 to 2008, our total sources of cash amounted to $104 billion, whilst our total uses of cash amounted to $112 billion. The net cash usage of $8 billion was financed by an increase in finance debt of $13 billion over the three-year period, offset by an increase in our balance of cash and cash equivalents of $5 billion. During this period, the price of Brent has averaged $78.26 per barrel. The following table summarizes the three-year sources and uses of cash.

	$ billion
Sources of cash	
Net cash provided by operating activities	91
Divestments	13
	104
Uses of cash	
Capital expenditure	58
Acquisitions	2
Net repurchase of shares	25
Dividends to BP shareholders	26
Dividends to minority interests	1
	112
Net use of cash	(8)
Financed by	
Increase in finance debt	(13)
Increase in cash and cash equivalents	5
	(8)

Acquisitions made for cash were more than offset by divestments. Net investment during the same period has averaged $16 billion per year. Dividends to BP shareholders, which grew on average by 16.8% per year in dollar terms, used $26 billion. Net repurchase of shares was $25 billion, which includes $26 billion in respect of our share buyback programme less net proceeds from shares issued in connection with employee share schemes. Finally, cash was used to strengthen the financial condition of certain of our pension plans. In the past three years, $2 billion has been contributed to funded pension plans. This is reflected in net cash provided by operating activities in the table above.

Trend information

We expect the short-term outlook for oil prices to be impacted by OPEC cuts on the one hand, and the outlook for the world economy and oil demand on the other. We expect continued volatility and our current expectation is that oil prices, relative to 2008, will continue to be low in 2009, and that this could extend into 2010.

In Exploration and Production, total production is expected to be somewhat higher in 2009. The actual growth rate will depend on a number of factors, including our pace of capital spending, the efficiency of that spend (in turn depending on industry cost deflation), the oil price and its impact on PSAs as well as OPEC quota restrictions.

In Refining and Marketing, 2009 is expected to be a challenging environment with reduced demand for our products, leading to lower volumes and pressure on margins. The impact is expected to be greatest in the petrochemicals sector. In 2009, with our US refining system fully operational, we expect our overall refining availability to be higher than in 2008.

Performance review

During 2008, we established momentum in cost control, mitigating the cost inflation that was primarily driven by rising oil prices. In 2009, our highest priority will continue to be achieving safe, compliant and reliable operations and we intend to continue our focus on cost efficiency. We expect cost deflation to be increasingly visible as we move through 2009.

We expect capital expenditure, excluding acquisitions and asset exchanges, to be around $20-21 billion in 2009. This reflects our intention in Exploration and Production to maintain investment whilst vigorously working to drive down costs and to reduce spending in our Refining and Marketing and Alternative Energy businesses in keeping with the current weak economic environment. We expect disposal proceeds to be between $2-3 billion in 2009.

On the basis of our current plans, we expect cash inflows and outflows in 2009 would balance at oil prices of around $60/bbl, taking account of expected disposal proceeds. We would expect that break even point to lower as we realize the benefits of our operational momentum and our action on costs.

Dividends and other distributions to shareholders

The total dividend paid to BP shareholders in 2008 was $10,342 million, compared with $8,106 million for 2007. The dividend paid per share was 55.05 cents, an increase of 30% compared with 2007. In sterling terms, the dividend increased 40% due to the strengthening of the dollar relative to sterling. We determine the dividend in US dollars, the economic currency of BP.

During 2008, the company repurchased 269.8 million of its own shares for cancellation at a cost of $2.9 billion. The repurchased shares had a nominal value of $67.5 million and represented 1.4% of ordinary shares in issue, net of treasury shares, at the end of 2007. Since the inception of the share repurchase programme in 2000, we have repurchased 4,929 million shares at a cost of $51.1 billion.

Our aim is to strike the right balance for shareholders, between current returns via the dividend, sustained investment for long-term growth, and maintaining a prudent gearing level. At the beginning of 2008, we rebalanced our distributions away from share buybacks in favour of dividends.

BP intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian shareholders also includes a dividend reinvestment feature.

The discussion above and following contains forward-looking statements with regard to oil prices, production, demand for refining products, refining volumes and margins and impact on the petrochemicals sector, refining availability, continuing priority of safe, compliant and reliable operations, and focus on cost efficiency, cost deflation, capital expenditure, expected disposal proceeds, cash flows, shareholder distributions, gearing, working capital, guarantees, expected payments under contractual and commercial commitments and purchase obligations. These forward-looking statements are based on assumptions that management believes to be reasonable in the light of the group s operational and financial experience. However, no assurance can be given that the forward-looking statements will be realized. You are urged to read the cautionary statement under Forward-looking statements on page 10 and Risk factors on pages 8-10, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The company provides no commitment to update the forward-looking statements or to publish financial projections for forward-looking statements in the future.

Financing the group s activities

The group s principal commodity, oil, is priced internationally in US dollars. Group policy has been to minimize economic exposure to currency movements by financing operations with US dollar debt wherever possible, otherwise by using currency swaps when funds have been raised in currencies other than US dollars.

The group s finance debt is almost entirely in US dollars and at 31 December 2008 amounted to $33,204 million (2007 $31,045 million) of which $15,740 million (2007 $15,394 million) was short term.

Net debt was $25,041 million at the end of 2008, a decrease of $1,776 million compared with 2007. We believe that a net debt ratio, that is net debt to net debt plus equity, of 20-30% provides an efficient capital structure and the appropriate level of financial flexibility. The net debt ratio was 21% at the end of 2008 and 22% at the end of 2007, close to the lower end of our target band. Net debt, which BP uses as a measure of financial gearing, includes the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed.

The maturity profile and fixed/floating rate characteristics of the group s debt are described in Financial statements Note 28 on page 140 and Note 35 on page 153.

We have in place a European Debt Issuance Programme (DIP) under which the group may raise $20 billion of debt for maturities of one month or longer. At 31 December 2008, the amount drawn down against the DIP was $10,334 million (2007 $10,438 million).

In addition, the group has in place a US Shelf Registration under which it may raise $10 billion of debt with maturities of one month or longer. At 31 December 2008, the amount raised under the US Shelf Registration was $6,500 million (2007 $2,500 million).

Commercial paper markets in the US and Europe are a primary source of liquidity for the group. At 31 December 2008, the outstanding commercial paper amounted to $4,268 million (2007 $5,881 million).

The group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At 31 December 2008, the group had available undrawn committed borrowing facilities of $4,950 million (2007 $4,950 million).

Despite current uncertainty in the financial markets, including a lack of liquidity for some borrowers, we have been able to issue $5 billion of long-term debt in the fourth quarter of 2008. In addition, we have been able to issue short-term commercial paper at competitive rates. In the context of unforeseen market volatility, we have however, increased the cash and cash equivalents held by the group to $8.2 billion at the end of 2008, compared with $3.6 billion at the end of 2007.

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities available, the group has sufficient working capital for foreseeable requirements.

Off-balance sheet arrangements

At 31 December 2008, the group s share of third-party finance debt of equity-accounted entities was $6,675 million (2007 $6,764 million). These amounts are not reflected in the group s debt on the balance sheet.

The group has issued third-party guarantees under which amounts outstanding at 31 December 2008 are summarized on the following page. Some guarantees outstanding are in respect of borrowings of jointly controlled entities and associates noted above. The analysis by time period indicates the ultimate expiry of the guarantees.

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							$ million
							Guarantees expiring by period
	Total	2009	2010	2011	2012	2013	2014 and thereafter
Guarantees issued in respect of[a]							
Liabilities and borrowings of jointly controlled entities and associates	223	70	32	25	6	6	84
Liabilities and borrowings of other third parties	613	94	19	30	35	34	401

[a]Of the amounts shown in the table, $215 million of the jointly controlled entities and associates guarantees relate to guarantees of borrowings and for other third party guarantees, $582 million relates to guarantees of borrowings.

Contractual commitments

The following table summarizes the group s principal contractual obligations at 31 December 2008. Further information on borrowings and finance leases is given in Financial statements Note 35 on page 153 and more information on operating leases is given in Financial statements Note 16 on page 130.

							$ million
							Payments due by period
Expected payments by period under contractual obligations and commercial commitments	Total	2009	2010	2011	2012	2013	2014 and thereafter
Borrowings[a]	35,192	16,554	5,817	3,303	2,577	5,014	1,927
Finance lease future minimum lease payments	916	116	117	116	70	58	439
Operating leases[b]	18,795	4,135	3,215	2,340	1,897	1,688	5,520
Decommissioning liabilities	12,347	348	361	211	157	197	11,073
Environmental liabilities	1,797	422	380	204	177	129	485
Pensions and other post-retirement benefits[c]	26,288	1,105	1,352	1,346	1,346	1,342	19,797
Purchase obligations[d]	115,642	64,479	13,317	6,559	5,100	4,531	21,656
Total	210,977	87,159	24,559	14,079	11,324	12,959	60,897

[a]Expected payments include interest payments on borrowings totalling $2,607 million ($907 million in 2009, $608 million in 2010, $421 million in 2011, $318 million in 2012, $236 million in 2013 and $117 million thereafter).

[b]The future minimum lease payments are before deducting related rental income from operating sub-leases. Where an operating lease is entered into solely by the group as the operator of a jointly controlled asset, the total cost is included irrespective of any amounts that will be reimbursed by joint venture partners. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

[c]Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post- retirement benefits.

[d]Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2009 include purchase commitments existing at 31 December 2008 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements Note 28 on page 140.

The following table summarizes the nature of the group s unconditional purchase obligations.

							$ million
							Payments due by period
Purchase obligations	Total	2009	2010	2011	2012	2013	2014 and thereafter
Crude oil and oil products	42,261	31,308	2,972	970	1,203	953	4,855
Natural gas	43,242	22,949	5,982	2,844	1,837	1,619	8,011
Chemicals and other refinery feedstocks	12,223	3,010	1,724	1,295	837	847	4,510
Power	6,156	4,910	1,168	60	16	2	
Utilities	690	111	101	86	83	57	252
Transportation	3,820	759	464	416	341	314	1,526
Use of facilities and services	7,250	1,432	906	888	783	739	2,502
Total	115,642	64,479	13,317	6,559	5,100	4,531	21,656

The group expects its total capital expenditure, excluding acquisitions and asset exchanges to be around $20-21 billion in 2009. The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2008 and the proportion of that expenditure for which contracts have been placed. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For jointly controlled assets, the net BP share is included in the amounts shown. Where operating lease costs are incurred in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project. Such costs are included in the amounts shown.

Capital expenditure commitments	Total	2009	2010	2011	2012	2013	$ million 2014 and thereafter
Committed on major projects	35,845	14,936	8,154	5,175	3,136	1,580	2,864
Amounts for which contracts have been placed	14,062	8,175	2,908	1,197	621	402	759

In addition, at 31 December 2008, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1.2 billion. Contracts were in place for $0.8 billion of this total.

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Performance review

Critical accounting policies
The significant accounting policies of the group are summarized in Financial statements Note 1 on page 106.

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides more information about the critical accounting policies that could have a significant impact on the results of the group and should be read in conjunction with the Notes on financial statements.

The accounting policies and areas that require the most significant judgements and estimates used in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves, the recoverability of asset carrying values, taxation, derivative financial instruments, provisions and contingencies, and pensions and other post-retirement benefits.

Oil and natural gas accounting

The group follows the successful efforts method of accounting for its oil and natural gas exploration and production activities.

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred.

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration.

For exploration wells and exploratory-type stratigraphic test wells, costs directly associated with the drilling of wells are initially capitalized within intangible assets, pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. The determination is usually made within one year after well completion, but can take longer, depending on the complexity of the geological structure. If the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploration wells that discover potentially economic quantities of oil and gas and are in areas where major capital expenditure (e.g. offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration appraisal work is under way or firmly planned.

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field is performed or while the optimum development plans and timing are established.
All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of exploration licence and leasehold property acquisition costs and costs associated with exploration wells and exploratory-type stratigraphic test wells, are transferred to production assets within property, plant and equipment.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. Field development costs subject to depreciation are expenditures incurred to date, together with approved future development expenditure required to develop reserves.

The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

Producing wells proved developed reserves.

Licence and property acquisition, field development and future decommissioning costs total proved reserves.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. If proved reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property s carrying value (*see discussion of recoverability of asset carrying values on the following page*).

At the end of 2006, BP adopted the SEC rules for estimating reserves instead of the UK accounting rules contained in the UK Statement of Recommended Practice. These changes are explained in Financial statements Note 10 on page 125.

The estimation of oil and natural gas reserves and BP s process to manage reserves bookings is described in Exploration and Production - Reserves and production on page 14. As discussed on the following page, oil and natural gas reserves have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements.

The 2008 movements in proved reserves are reflected in the tables showing movements in oil and gas reserves by region in Financial statements Supplementary information on oil and natural gas on pages 185 to 193.

Performance review

Recoverability of asset carrying values

BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable and, as a result, charges for impairment are recognized in the group s results from time to time. Such indicators include changes in the group s business plans, changes in commodity prices leading to unprofitable performance, low plant utilization, evidence of physical damage and, for oil and gas properties, significant downward revisions of estimated volumes or increases in estimated future development expenditure. If there are low oil prices, natural gas prices, refining margins or marketing margins during an extended period, the group may need to recognize significant impairment charges.

The assessment for impairment entails comparing the carrying value of the cash-generating unit with its recoverable amount, that is, the higher of fair value less costs to sell and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products.

For oil and natural gas properties, the expected future cash flows are estimated based on the group s plans to continue to develop and produce proved reserves and associated risk-adjusted probable and possible volumes. Expected future cash flows from the sale or production of these volumes are calculated based on the management s best estimate of future oil and gas prices. Prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the group s long-term planning assumptions thereafter. As at 31 December 2008, the group s long-term planning assumptions were $75 per barrel for Brent and $7.50/mmBtu for Henry Hub (2007 $60 per barrel and $7.50/mmBtu). These long-term planning assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. Typically rates of 11% or 13% are used (2007 11% or 13%). The rate applied in each country is re-assessed each year by analyzing relevant information.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $9.9 billion on its balance sheet, principally relating to the Atlantic Richfield and Burmah Castrol acquisitions. In testing goodwill for impairment, the group uses a similar approach to that described above. If there are low oil prices or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize significant goodwill impairment charges.

Taxation

The computation of the group s income tax expense involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome.

In addition, the group has carry-forward tax losses in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses can be utilized. Management judgement is exercised in assessing whether this is the case.

To the extent that actual outcomes differ from management s estimates, taxation charges or credits may arise in future periods. For more information see Financial statements Note 20 on page 133 and Note 44 on page 172.

Derivative financial instruments

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. In addition, derivatives embedded within other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. All such derivatives are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Gains and losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

In some cases the fair values of derivatives are estimated using models and other valuation methods due to the absence of quoted prices or other observable, market-corroborated data. In particular, this applies to the majority of the group s natural gas and LNG embedded derivatives. These are primarily long-term UK gas contracts that use pricing formulae not related to gas prices, for example, oil product and power prices. These contracts are valued using models with inputs that include price curves for each of the different products that are built up from active market pricing data and extrapolated to the expiry of the contracts using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships. Price volatility is also an input for the models. Changes in the key assumptions could have a material impact on the gains and losses on embedded derivatives recognized in the income statement. For more information see Financial statements - Note 34 on page 148. An analysis of the sensitivity of the fair value of the natural gas and LNG derivatives to changes in the key assumptions is provided in Financial statements - Note 28 on page 140.

Performance review

Provisions and contingencies

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued on the installation of those facilities, reflecting our legal obligations at that time. A corresponding asset of an amount equivalent to the provision is also created within property, plant and equipment. This asset is depreciated over the expected life of the production facility or pipeline. Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Changes in the expected future costs are reflected in both the provision and the asset.

Decommissioning provisions associated with downstream and petrochemicals facilities are generally not provided for, as such potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2008 was 2%, unchanged from the end of 2007. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of cash outflow can be reliably estimated. The timing of recognition requires the application of judgement to existing facts and circumstances, which can be subject to change. Since the actual cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

A change in estimate of a recognized provision or liability would result in a charge or credit to net income in the period in which the change occurs (with the exception of decommissioning costs as described above).

Provisions for environmental clean-up and remediation costs are based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2008 was 2%, the same rate as at the previous balance sheet date.

As further described in Financial statements Note 44 on page 172, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be adjusted. Accordingly, significant management judgement relating to contingent liabilities is required, since the outcome of litigation is difficult to predict.

Pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, healthcare cost trend rates and rates of utilization of healthcare services by retirees. These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the group s defined benefit pension and post-retirement plans is important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year to year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also affect future results of operations.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year-end and hence the surpluses and deficits recorded on the group s balance sheet, and pension and other post-retirement benefit expense for the following year.

The pension and other post-retirement benefit assumptions at 31 December 2008, 2007 and 2006 are provided in Financial statements Note 38 on page 157.

The assumed rate of investment return, discount rate and the US healthcare cost trend rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Financial statements - Note 38 on page 157.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP s most substantial pension liabilities are in the UK, US and Germany and the mortality assumptions for these countries are detailed in Financial statements - Note 38 on page 157.

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Board performance
and biographies

Directors and senior management

Directors and senior management
The following lists the company s directors and senior management as at 18 February 2009.

Name		Initially elected or appointed
P D Sutherland	Chairman	Chairman since May 1997 Director since July 1995
Sir Ian Prosser	Non-Executive Deputy Chairman	Deputy chairman since February 1999 Director since May 1997
A Burgmans	Non-Executive Director	February 2004
C B Carroll	Non-Executive Director	June 2007
Sir William Castell	Non-Executive Director	July 2006
G David	Non-Executive Director	February 2008
E B Davis, Jr	Non-Executive Director	December 1998
D J Flint	Non-Executive Director	January 2005
Dr D S Julius	Non-Executive Director	November 2001
Sir Tom McKillop	Non-Executive Director	July 2004
Dr A B Hayward	Executive Director (Group Chief Executive)	Group Chief Executive since May 2007 Director since February 2003
I C Conn	Executive Director (Chief Executive, Refining and Marketing)	July 2004
Dr B E Grote	Executive Director (Chief Financial Officer)	August 2000
A G Inglis	Executive Director (Chief Executive, Exploration and Production)	February 2007
R Bondy	Group General Counsel	May 2008
S Bott	Executive Vice President, Human Resources	March 2005
V Cox	Executive Vice President, Alternative Energy	July 2004
H L McKay	Executive Vice President (Chairman and President of BP America Inc.)	June 2008
J Mogford	Executive Vice President (Chief Operating Officer, Refining and US Fuels Value Chains)	October 2007
S Westwell	Executive Vice President (Group Chief of Staff)	January 2008

Mr H L McKay, previously executive vice president (special projects), was appointed chairman and president of BP America Inc. on the retirement of Mr R A Malone on 1 February 2009.
Dr D C Allen retired as a director on 31 March 2008 and Dr W E Massey retired as a director on 17 April 2008. Mr G David was appointed a non-executive director on 11 February 2008. At the company s 2008 annual general meeting (AGM), the following directors retired, offered themselves for election/re-election and were duly elected/re-elected: Mr A Burgmans; Mrs C B Carroll; Sir William Castell; Mr I C Conn; Mr G David, Mr E B Davis, Jr; Mr D J Flint; Dr B E Grote; Dr A B Hayward; Mr A G Inglis; Dr D S Julius; Sir Tom McKillop; Sir Ian Prosser and Mr P D Sutherland.
Mr R Dudley has been appointed to the board with effect from 6 April 2009. All of the directors, including Mr Dudley, will offer themselves for election/ re-election at the company s 2009 AGM.

David Jackson (56) was appointed company secretary in 2003. A solicitor, he is a director of BP Pension Trustees Limited and a member of the Listing Authorities Advisory Committee.

Directors and senior management

Directors

P D Sutherland, SC, KCMG

Chairman of the chairman s and the nomination committees and attends meetings of the remuneration committee

Peter Sutherland (62) rejoined BP s board in 1995, having been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and was a non-executive director of The Royal Bank of Scotland Group PLC from 2001 to 6 February 2009.

Sir Ian Prosser

Member of the chairman s, the nomination and the remuneration committees and chairman of the audit committee

Sir Ian (65) joined BP s board in 1997 and was appointed non-executive deputy chairman in 1999. He is the senior independent director. In 2003, he retired as chairman of InterContinental Hotels Group PLC, a spin-off from the former Bass PLC where he was chief executive.

He is a non-executive director and senior independent director of GlaxoSmithKline plc, a non-executive director of the Sara Lee Corporation and non-executive chairman of The Navy, Army and Air Force Institutes (NAAFI). He was previously on the boards of The Boots Company PLC and Lloyds TSB PLC.

A Burgmans, KBE

Member of the chairman s and the safety, ethics and environment assurance committees

Antony Burgmans (62) joined BP s board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. In 2005, he became non-executive chairman of Unilever PLC and Unilever NV, retiring from these appointments in May 2007. He is also a member of the supervisory boards of Akzo Nobel NV and Aegon NV.

C B Carroll

Member of the chairman s and safety, ethics and environment assurance committees

Cynthia Carroll (52) joined BP s board in June 2007. She started her career at Amoco and in 1989 she joined Alcan, where in 2002 she was appointed president and chief executive officer of Alcan s primary metals group and an officer of Alcan, Inc. She was appointed as chief executive of Anglo American plc, the global mining group, in March 2007. She is also a director of De Beers s.a. and Anglo Platinum Ltd.

Sir William Castell, LVO

Member of the chairman s committee and chairman of the safety, ethics and environment assurance committee

Sir William (61) joined BP s board in 2006. From 1990 to 2004, he was chief executive of Amersham plc and subsequently president and chief executive officer of GE Healthcare. He was appointed as a vice chairman of the board of GE in 2004, stepping down from this post in 2006 when he became chairman of the Wellcome Trust. He remains a non-executive director of GE.

G David

Member of the chairman s and the audit committees

George David (66) joined BP s board on 11 February 2008. He has spent his career with United Technologies Corporation (UTC), as its chief executive officer from 1994 to 2008 and chairman since 1997. He joined UTC s Otis elevator subsidiary in 1975.

E B Davis, Jr

Member of the chairman s, the audit and the remuneration committees

Erroll B Davis, Jr (64) joined BP s board in 1998, having previously been a director of Amoco. He was chairman and chief executive officer of Alliant Energy, relinquishing this dual appointment in 2005. He continued as chairman of Alliant Energy until February 2006, leaving to become chancellor of the University System of Georgia. He is a member of the board of General Motors Corporation and Union Pacific Corporation.

D J Flint, CBE

Member of the chairman s and the audit committees

Douglas Flint (53) joined BP s board in 2005. He trained as a chartered accountant and became a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc. He was chairman of the Financial

Reporting Council s review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

Dr D S Julius, CBE

Member of the chairman s and the nomination committees and chairman of the remuneration committee

DeAnne Julius (59) joined BP s board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Roche Holdings SA and Jones Lang LaSalle, Inc.

Sir Tom McKillop

Member of the chairman s, the remuneration and the safety, ethics and environment assurance committees

Sir Tom (65) joined BP s board in 2004. Sir Tom was chief executive of AstraZeneca PLC from the merger of Astra AB and Zeneca Group PLC in 1999 until December 2005. He was a non-executive director of Lloyds TSB Group PLC until 2004 and was appointed to the board of The Royal Bank of Scotland Group PLC in 2005, where he was chairman from 2006 to 3 February 2009.

Dr A B Hayward

Tony Hayward (51) joined BP in 1982. He held a series of roles in exploration and production, becoming a director of exploration and production in 1997. In 2000, he was made group treasurer, and an executive vice president in 2002. He was chief executive officer of exploration and production between 2002 and February 2007. He became an executive director of BP in 2003 and was appointed as group chief executive in May 2007. Dr Hayward is a non-executive director and senior independent director of Tata Steel.

I C Conn

Iain Conn (46) joined BP in 1986. Following a variety of roles in oil trading, commercial refining, retail and commercial marketing operations, and exploration and production, in 2000 he became group vice president of BP s refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in 2004. He was appointed chief executive of refining and marketing in June 2007. He is a non-executive director and senior independent director of Rolls-Royce Group plc.

Directors and senior management

Dr B E Grote
Byron Grote (60) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of exploration and production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002. He is a non-executive director of Unilever NV and Unilever PLC.
A G Inglis
Andy Inglis (49) joined BP in 1980, working on various North Sea projects. Following a series of commercial roles in exploration, in 1996 he became chief of staff, exploration and production. From 1997 until 1999, he was responsible for leading BP s activities in the deepwater Gulf of Mexico. In 1999, he was appointed vice president of BP s US western gas business unit. In 2004, he became executive vice president and deputy chief executive of exploration and production. He was appointed chief executive of BP s exploration and production business and an executive director in February 2007. He is a non-executive director of BAE Systems plc.
Senior management
R Bondy
Rupert Bondy (47) joined BP as group general counsel in May 2008. In 1989 he joined US law firm Morrison & Foerster, working in San Francisco and London. From 1994 to 1995, he worked for UK law firm Lovells in London. In 1995, he joined SmithKline Beecham as senior counsel for mergers and acquisitions and other corporate matters. He subsequently held positions of increasing responsibility and following the merger of SmithKline Beecham and GlaxoWellcome he was appointed senior vice president and general counsel of GlaxoSmithKline in 2001.
S Bott
Sally Bott (59) joined BP in 2005 as an executive vice president responsible for global human resources. Sally joined Citibank in 1970 and, following a variety of roles, was appointed a vice president in human resources in 1979 and subsequently held a series of positions as a human resources director to sectors of Citibank. In 1994, she joined Barclays De Zoete Wedd, an investment bank, as head of human resources and in 1997 became group human resources director of Barclays plc. From 2000 to early 2005, she was managing director of Marsh and McLennan and head of global human resources at Marsh Inc. In 2008, Sally was elected as a non-executive director of UBS AG.
V Cox
Vivienne Cox (49) joined BP in 1981. Following a series of commercial roles, she was appointed chief executive of Air BP in 1998. From 1999 until 2001, she was group vice president of BP Oil, responsible for business-to-business marketing and oil supply and trading. From 2001 to 2004, she was group vice president for integrated supply and trading. In 2004, she was appointed an executive vice president, responsible for gas, power and renewables in addition to the supply and trading businesses. In late 2005, she became responsible for Alternative Energy. She is a non-executive director of Rio Tinto plc and Climate Change Capital Limited.
H L McKay
Lamar McKay (50) was appointed chairman and president of BP America, Inc. from 1 February 2009. He joined Amoco Production Company as a petroleum engineer in 1980 and later served in a variety of operating, commercial and M&A roles. In 1993, he became general manager of Arkoma Basin and in 1997, the business unit leader for the Gulf of Mexico Shelf. During 1998-2000, he worked on the BP-Amoco merger and served as general manager for BP p.l.c. worldwide exploration and production strategy and planning. In 2000, he became business unit leader for the Central North Sea in Aberdeen, and subsequently chief of staff for worldwide exploration and production in London, following which he served as chief of staff for the BP deputy group chief executive. Lamar then worked as group vice president for Russia & Kazakhstan, during which time he was appointed to the board of TNK-BP. He was named executive vice-president of BP America and COO in the USA in May 2007. In early 2008, he became executive vice president of BP p.l.c. special projects, focusing on Russia, subsequently joining the group executive management team in June 2008.
J Mogford

John Mogford (55) joined BP in 1977, spending the early part of his career in a variety of drilling and production roles. In 1999, he became group vice president for health, safety and the environment before being appointed as group vice president for gas, power and renewables in 2002. In 2004, he returned to exploration and production as group vice president (technology and functions). In 2005, he was appointed as senior group vice president of safety and operations before becoming executive vice president, safety and operations in October 2007. He became chief operating officer of refining from 1 March 2008. On 15 January 2009, he moved to chief operating officer for US fuels value chains and head of refining.

S Westwell

Steve Westwell (50) joined BP in the manufacturing and supply division of BP Southern Africa in 1988. Following various retail positions in the UK and the US he was appointed head of retail and a member of the board of BP Southern Africa Pty. In 2003, he became president and chief executive officer of BP solar, and in 2004, group vice president of natural gas liquids, power, solar and renewables. In 2005, he was appointed group vice president of alternative energy. He was appointed group chief of staff on 1 January 2008.

BP board performance report

BP board performance report

Letter from the chairman

I am once again pleased to introduce our board performance report. The report reviews the work of the board and its committees as my tenure as chairman moves to a close. Over the past 12 years, both the calibre of individuals who have served on the board and our system of governance has stood us in good stead. The strong set of principles on which we base our governance framework, which include clarity of roles, separation of powers, independence and appropriate skills, remain valid today.

I have been encouraged from discussions with shareholders over time that our approach to governance and the dialogue which we continue to have with them is welcomed. This is important to us and no more so than during the testing times in which we operate.

Recent events and the current economic climate have inevitably triggered further debate about governance. This I welcome. The framework of governance does need to be kept under review and, where necessary, challenged by investors, regulators and companies themselves to ensure that the system is delivering.

Under such a review I believe that BP s governance approach can show its strength. It requires active engagement on behalf of the company and investors alike. I do not believe that our comply or explain system is broken and it is important for us that the principles-based system continues.

Peter Sutherland
Chairman
24 February 2009

Board governance principles

The board governance principles (principles) are designed to enable the board and the executive management to operate within a clear framework. The principles describe the role of the board, its processes, its relationship with executive management and the main tasks and requirements of the board committees. The principles are available at *www.bp.com/corporategovernance*.

In carrying out its work, the board focuses on key tasks, which include the active review of the long-term strategy and the annual plan, monitoring the decisions and actions of the group chief executive, the performance of BP, the succession of executive management and the oversight of risk.

The principles outline how the board delegates its authority for executive management of the company to the group chief executive, subject to monitoring by the board and a clearly defined set of limitations. These executive limitations require that any executive action taken in the course of business takes specific issues into consideration, including health, safety and the environment, any reputational impact on BP, risk and the framework for internal control.

Operating the principles

The group chief executive through the annual plan describes to the board how the strategy is to be delivered, together with an assessment of the group s risks. During the year, the board monitors progress and keeps the strategy under review.

The group chief executive is obliged to review and discuss with the board all strategic projects or developments and all material matters currently or prospectively affecting the company and its performance.

The principles are kept under review by the board to ensure they remain relevant and up to date.

Board activities in 2008

As outlined above, the board focuses on key areas in carrying out its work. Forward agendas are set to determine a high level work programme for the board based on its core tasks (including dealing with strategy and monitoring) but additional items are added throughout the
year depending on the exigencies of the business as they arise. During the year the board was involved in the following activities:

Strategy and Risk

The board undertook extensive discussions on strategic options for the group, including the future business and competitive environment, technology developments, pricing and demand models and portfolio options. The identification and management of group risks were reviewed by the board, together with how these risks and their mitigation were embedded in the group s annual plan.

Review of capital expenditure and post investment review

While the audit committee reviewed project delivery performance, the board undertook an annual review of the group s project sanctioning process and delegation of authority. The process and criteria for each stage of a project was discussed, together with examples of projects with different lead times and complexities.

Business review

Business reviews were held with both segments (Exploration and Production and Refining and Marketing) and the finance and information technology and services (IT&S) functions.

Global economic environment and energy markets

The board actively monitored developments in the global energy markets and economic environment. Issues considered included the supply/demand balance, the relationship between oil prices, energy consumption and GDP growth and turbulence in the financial markets.

Other areas

Other areas discussed by the board included interactions with BP s partners in TNK-BP, the results of a group-wide employee satisfaction survey and the findings of a report on BP s reputation in the UK and US. The board also received a presentation from the independent expert appointed to provide an objective assessment of BP s progress in implementing the recommendations of the BP US Refineries Independent Safety Review Panel (the Panel).

The board is supported in its tasks by the company secretary, who reports to the chairman and has no executive functions. His remuneration is determined by the remuneration committee.

Board meetings and attendance

The board met nine times during 2008, of which one meeting was a two-day strategy session and another meeting was a one-day strategy session.

	Board meetings eligible to attend	Board meetings attended
P D Sutherland	9	9
Sir Ian Prosser	9	9
A Burgmans	9	9
C B Carroll	9	9
Sir William Castell	9	9
G David	7	7
E B Davis, Jr	9	8
D J Flint	9	7
Dr D S Julius	9	9
Sir Tom McKillop	9	9
Dr W E Massey	4	4
Dr D C Allen	3	3
I C Conn	9	9
Dr B E Grote	9	9
Dr A B Hayward	9	9
A G Inglis	9	9

BP board performance report

The chairman and senior independent director
The principles require that neither the chairman nor deputy chairman be employed as an executive of the group. During 2008, these posts were held by Peter Sutherland and Sir Ian Prosser respectively.

The chairman provides leadership of the board, acts as facilitator for meetings and ensures that the governance framework of the board is maintained and operated. The chairman also leads board performance appraisals. He represents the views of the board to shareholders on key issues, in particular those relating to governance and succession planning and informs the board of shareholder views.

Between board meetings, the chairman has responsibility for ensuring the integrity and effectiveness of the relationship with executive management. This requires his interaction with the group chief executive, as well as his contact with other board members, senior management and stakeholders.

The deputy chairman acts for the chairman in his absence or at his request. The deputy chairman also serves as the board s senior independent director and is available to shareholders where there are issues that cannot be addressed through normal channels.

The chairman and all the non-executive directors meet periodically without the presence of executive management as the chairman s committee. The performance of the chairman is evaluated each year, with the evaluation discussion taking place when the chairman is not present. The principles require that the board develop and maintain a plan for the succession of both the chairman and deputy chairman.

Board composition
The principles require that over half the board, excluding the chairman, comprise independent non-executive directors and that the number of directors to not normally exceed 16. The board is composed of the chairman, nine non-executive and four executive directors.

The board considers that it is of an appropriate size to govern BP, with its directors possessing the relevant backgrounds and mix of experience, knowledge and skills to maximize its effectiveness.

Board renewal and skills
The board remains actively engaged in orderly succession planning for both executive and non-executive directors and is assisted in this task by the nomination committee. The committee keeps under review the composition, skills and diversity of the board to ensure that it remains appropriate to the tasks and work it undertakes. The nomination committee believes a breadth of skills is required for the board to meet the demands of a business with global operations. These skills include deep operational, engineering, safety and financial expertise, experience of leading industrial, capital intensive or long lead time businesses and insight into key emerging markets and technology development.

The board: terms of appointment
The chairman and non-executive directors of BP serve on the basis of letters of appointment. Executive directors of BP have service contracts with the company. Details of all payments to directors are described in the directors remuneration report.

The service contracts of executive directors are expressed to expire at a normal retirement age of 60 (subject to age discrimination), while non-executive directors ordinarily retire at the AGM following their 70th birthday.

In accordance with BP s Articles of Association, directors are granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors and officers liability insurance policy throughout 2008. During the year, a review of the terms and nature of the policy was undertaken and has been renewed for 2009. Although their defence costs may be met, neither the company s indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. Following recent changes to company law, the company is also permitted to advance costs to directors for their defence in investigations or legal actions.

Director elections

New board directors are subject to election by shareholders at the first AGM following their appointment. All existing directors stand for re-election each year a practice the company has followed since 2004. All directors proposed to shareholders for election are accompanied by a biography and a description of the skills and experience that the company feels are relevant.

Voting levels at the 2008 AGM demonstrated continued support for all board directors.

Board independence

Non-executive directors are required by the principles to be independent in character and free from any business or other relationship that could materially interfere with the exercise of their judgement. The board has determined that the non-executive directors who served during 2008 fulfilled this requirement and were independent.

BP believes that tenure of board members should be determined on the basis of contribution and continued evidence of the exercise of independent judgement. As all directors are proposed for annual re-election by shareholders, the board considers that arbitrary term limits on a director s service are not appropriate.

Sir Ian Prosser joined the board in 1997. It is the view of the board that he remains firmly independent. His experience and long-term perspective on BP s business have provided and continue to provide a valuable contribution to the board and the audit committee, which he chairs. As deputy chairman and senior independent director, Sir Ian is leading the board s search for the successor to the current chairman. He has been asked by the board to remain in post until April 2010 in order that he may conclude both the chairman s succession process and the identification and appointment by the new chairman of a senior independent director.

Mr Davis joined the board on the completion of the Amoco merger in December 1998. The board believes Mr Davis continues to demonstrate his independence. He is an active participant at the board and sits on the audit and remuneration committees, and the high level of his independence is demonstrated by his engagement in these forums.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities).

From 1 October 2008, there has been a requirement that directors must avoid a situation where they have, or can have, a direct or indirect interest that conflicts, or possibly may conflict, with the company s interests. Directors of public companies may authorize conflicts and potential conflicts, where appropriate, if a company s articles of association permit and shareholders have approved appropriate amendments.

Procedures have been put in place for the disclosure by directors of any such conflicts and also for the consideration and authorization of these conflicts by the board. These procedures allow for the imposition of limits or conditions by the board when authorizing any conflict, if they think this is appropriate. These procedures were duly followed to approve appropriate conflicts immediately prior to the enactment of the conflict provisions in October 2008, and are now included as a regular standing item for consideration by the board at its meetings.

BP board performance report

Serving as a director

Induction

The induction of new board members is the responsibility of the chairman, who is assisted by the company secretary in this task. All new directors receive a full induction programme, including a core element covering the principles and the legal and regulatory duties of directors. Non-executive directors receive further induction content devised according to their own interests and needs, together with the requirements of the committees on which they will serve. This would include meetings and briefings on the operations and activities of the group, the strategy and the annual plan and the company s financial performance. The induction programme is targeted for completion within the first nine to 12 months of non-executive directors taking office, while the executive director programme is arranged in the course of their business activities.

Training and site visits

Directors and committee members receive briefings on BP s business, its markets, operating environment and other key issues during their tenure as directors to ensure they have the necessary skill and knowledge to perform their duties effectively. Board members are also kept updated on legal and regulatory developments that may impact their duties and obligations as directors of a listed company.

In the past two years, the board and its committees have sought greater opportunity to meet at BP s operating sites. This has enabled board members to see a selection of BP s businesses e.g. the Texas City refinery, gas production in Colorado, exploration and production activities in Azerbaijan and the alternative energy solar facility in Maryland. These site visits have given directors the opportunity to meet both operational staff and government and community leaders in the parts of the world where BP operates. All non-executive directors are required to participate in at least one site visit per year.

Outside appointments

BP recognizes that executive directors may be invited to become non-executive directors of other companies and that such appointments can broaden their knowledge and experience, to the benefit of the individual and the group. Executive directors are permitted to take up one external board appointment, subject to the agreement of the chairman and reported to the BP board. Fees received for these external appointments may be retained by the executive director and are reported in the directors remuneration report.

Non-executive directors may serve on a number of outside boards, provided they continue to demonstrate the requisite commitment to discharge their duties to BP effectively. The nomination committee keeps under review the nature of directors other interests to ensure that the efficacy of the board is not compromised and may make recommendations to the board if it concludes that a director s other commitments are inconsistent with those required by BP.

Board evaluation

The principles stipulate that the performance and effectiveness of the board, including the work of its committees, should be evaluated annually. In 2008, this evaluation was undertaken internally with the use of a questionnaire. The questionnaire focused on areas including the conduct of meetings, activities of the board versus committees, monitoring and information and board support and built on the review of board operations and governance that had taken place in 2007. The main outcome of the evaluation was a requirement for a more systematic approach to ensure that the skills of the directors met the changing demands of the business and the environment in which it operates.

Engagement with shareholders

The board is accountable to shareholders for the performance and activities of the BP group and engages in regular dialogue to understand their views and preferences. However, the board also recognizes that, in conducting its business, BP should be responsive to other relevant constituencies.

During the year, the chairman and deputy chairman met with institutional shareholders to discuss issues relating to the board, governance, strategy and performance. The remuneration committee chairman met with larger shareholders to discuss executive director remuneration.

The group chief executive, other executive directors and senior management, company secretary s office, investor relations and other teams within BP also engage with a range of shareholders on wider issues relating to the group, including in particular its safety, operational and financial performance. Presentations given by the group to the investment community are available to download from the Investors section of BP s website, as are speeches on topics of broad interest to shareholders made by the group chief executive and other senior members of the management team.

AGM

BP s AGM enables shareholders to ask questions and hear the resulting discussion about the company s performance and the directors stewardship of the company. Votes on all matters (except procedural issues) are taken by a poll at the AGM, meaning that every vote cast -whether by proxy or in person at the meeting is counted.

The chairman, board committee chairmen and other directors were present during the 2008 AGM and met shareholders on an informal basis after the main business of the meeting. In 2008, voting levels at the AGM increased to 64%, compared with 61% in 2007. Last year was also the first time that the AGM was webcast. This will be repeated for the company s forthcoming meeting. The webcast, speeches and presentations given at the AGM are available to download from the BP website after the event, together with the outcome of voting on the resolutions.

Board committees

The principles allocate the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks prescribe the authority and role of the board committees.

Reports for each of the main board committees follow. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary s office, which is independent of the executive management of the group. The main tasks and requirements of each of the board s committees are set out in the principles, available at *www.bp.com/corporategovernance*.

Audit committee report

Membership

The audit committee comprises four independent non-executive directors who have been selected to provide a wide range of financial, international and commercial expertise appropriate to fulfil the committee s duties.

During the year, Sir Ian Prosser (chairman), Douglas Flint and Erroll Davis, Jr were members of the audit committee. Sir William Castell retired from the committee in April 2008 and George David joined in May 2008. The secretary to the committee is David Pearl, deputy company secretary of BP.

The board considers that Douglas Flint possesses the financial and audit committee experience, as defined by the Combined Code guidance and the SEC, and has nominated him as the audit committee s financial expert.

BP board performance report

Attendance

The audit committee met 13 times during 2008.

	Audit committee meetings eligible to attend	Audit committee meetings attended
Sir Ian Prosser (chairman)	13	13
E B Davis, Jr	13	10
D J Flint	13	13
G David	6	6
Sir William Castell (former member)	7	7

In addition to the above members, the committee invites the lead partner of the external auditors (Ernst & Young), the group chief financial officer, the general auditor (head of internal audit), the chief accounting officer and the deputy chief financial officer to attend each meeting. Other senior management attend on request to enable the committee to discharge its duties. The committee also holds private sessions during the year without the presence of executive management.

Role and authority of the audit committee

The audit committee assists the board in carrying out its responsibilities in relation to financial risk, internal controls, financial and regulatory reporting requirements and the broader observance of the executive limitations relating to financial matters.

The main tasks and requirements for the audit committee are set out in the principles. The audit committee believes that these meet each of the tasks and activities outlined by the Combined Code as falling within the remit of an audit committee.

Information

The committee receives information and reports from internal and external sources, including a wide cross-section of BP s business and financial control management, with the attendance of additional Ernst & Young staff if appropriate to a particular business or functional review.

The audit committee is able to access independent advice and counsel when needed, on an unrestricted basis. Further support is provided to the committee by the company secretary s office and during 2008 external specialist legal and regulatory advice was provided by Sullivan & Cromwell LLP.

The wider board is kept informed of the activities of the committee, and any issues that have arisen, through the regular update given by the audit committee chair after each meeting.

Training and induction

BP provides an induction programme for new committee members and ongoing training to assist them in carrying out their duties. Elements of the induction programme include familiarization with the tasks and requirements of the audit committee, an overview of the key financial and operational aspects of the businesses and an introduction to the group s system of internal control. During the year, George David participated in the audit committee induction, including private sessions with the lead external audit partner and the general auditor.

In 2008, the training programme for the audit committee included briefings on developments in financial reporting and financial standards, a site visit to BP s UK trading operations and an externally facilitated session on tax risk management.

Committee activities in 2008

The chart at the end of this section shows how the audit committee allocated its agenda time in 2008.

Financial reporting

During the year, the committee reviewed all financial reports, including the Annual Report and Accounts and Annual Report on Form 20-F, before recommending their publication to the board.

Monitoring risk in the business

In 2008, the audit committee reviewed reports on risks, controls and assurance for the BP business segments (Exploration and Production, Refining and Marketing), together with alternative energy, information technology and services, the proposed reorganization of the group finance function and BP s trading function. The committee also reviewed BP s long-term contractual commitments and the provisions made for environmental remediation and decommissioning.

Internal controls

A joint meeting with the safety, ethics and environment assurance committee was held to review the general auditor s report on internal controls and risk management. A further joint meeting was held in early 2009 to assist the board in its assessment of the effectiveness of internal controls and risk management in 2008.

The committee discussed key regulatory issues during the year as part of its standing agenda items, including the quarterly internal audit findings report and a review of the company s evaluation of its internal controls systems as part of the requirement of Section 404 of the Sarbanes-Oxley Act. The effectiveness of BP s enterprise level controls was examined through the annual assessment undertaken by the internal audit function.

External auditors

The lead audit partner from Ernst & Young attends all meetings of the audit committee at the request of the committee chairman. Other external audit staff are invited to attend meetings where their expertise is relevant to the agenda item, for example during business or technical reviews.

The committee held two private meetings during the year with the external auditors without the presence of BP management, in order to discuss issues or concerns from either the committee or the auditors.

Performance of the external auditors is evaluated by the audit committee each year, with particular scrutiny of their independence, objectivity and viability. Independence is maintained through the limiting of non-audit services to tax and audit-related work that fall within defined categories. This work is pre-approved by the audit committee and all non-audit services are monitored quarterly.

Fees paid to the external auditors for the year (*see Financial statements Note 18 on page 132*) were $67 million, of which 14% was for non-audit work. The fees and services provided by Ernst & Young for both audit and non-audit work have decreased in comparison to the previous year due to improved audit efficiency, ongoing systems improvements and BP s new business structure.

During the year, a new lead partner from Ernst & Young replaced the existing partner who had completed five years service on the BP audit in early 2008. Under BP policy and pursuant to external regulation, a new lead audit partner is appointed every five years and other senior audit staff are rotated every seven years. No partners or senior staff from Ernst & Young who are connected with the BP audit may transfer to the group.

The audit committee has considered both the proposed fee structure and the audit engagement terms for 2009 and has recommended to the board that the reappointment of the external auditors be proposed to shareholders at the 2009 AGM.

BP board performance report

Internal audit

The general auditor attends each committee meeting at the invitation of the audit committee chairman. With the retirement of the general auditor in early 2008, a new general auditor was appointed following an externally facilitated recruitment process.

During the year, the audit committee evaluated the performance of the internal audit function and agreed to the proposed programme of work for the year (being satisfied that it appropriately responded to the key risks facing the company and that the function had adequate staff and resources to complete its work).

In 2008, the committee met once with the general auditor in a private session without the presence of executive management. In addition, the general auditor met with the chairman of the committee from time to time between meetings.

Fraud and employee concerns on financial matters

The audit committee received an annual certification report from the group compliance and ethics function, together with quarterly reports that highlighted financial issues raised through OpenTalk, the group-wide employee concerns programme.

The committee further received quarterly updates from internal audit on instances of actual or potential fraud.

Audit committee activities

Approximate allocation of agenda time in 2008*

Committee performance evaluation

The committee conducts a yearly evaluation of its performance through one-to-one interviews or questionnaires. The results are collated and reported by the committee secretary. Actions taken in 2008 as a result of the end 2007 evaluation included participation in an externally facilitated training session and improved tracking of outstanding issues. In addition, the committee considers performance during its private sessions throughout the year.

The 2008 evaluation was conducted through individual interviews and the outcomes discussed by the committee in January 2009. The forward agenda for the year ahead was set following this review, and consideration was given to building on the training provided to members through site visits.

The audit committee plans to meet 13 times during 2009.

Safety, ethics and environment assurance committee report

Membership

The committee consists solely of independent non-executive directors who have been selected to provide a wide range of operational and international expertise appropriate to fulfil the committee s duties.

Members of the safety, ethics and environment assurance committee (SEEAC) during 2008 were Antony Burgmans, Sir William Castell and Sir Tom McKillop. Dr Massey retired as chairman of SEEAC in April 2008 and Sir William Castell became the committee chairman from that date. Cynthia Carroll joined the committee in June 2008. Support was provided by the committee secretary, David Pearl (deputy company secretary).

Attendance

SEEAC met eight times during 2008.

	SEEAC meetings eligible to attend	SEEAC meetings attended
Sir William Castell (chairman)	8	8
A Burgmans	8	8
C B Carroll	3	2
Sir Tom McKillop	8	8

Dr W E Massey (former member)	4	4

In addition to the above members, each SEEAC meeting is attended by the lead partner of the external auditors (Ernst & Young) and the BP general auditor (head of internal audit) on the invitation of the committee chairman. The group chief executive also attends committee meetings as the executive liaison with SEEAC: Dr Hayward attended all eight meetings of the committee in 2008. The committee holds private sessions without executive management in attendance at the end of each meeting.

Role and authority of the committee

The main tasks and requirements for SEEAC are set out in the principles and include among others:

Monitoring and obtaining assurance on behalf of the board that the management or mitigation of significant BP risks of a non-financial nature is appropriately addressed by the group chief executive.

Reviewing material to be placed before shareholders that addresses environmental, safety and ethical performance and make recommendations to the board about their adoption and publication.

Reviewing reports on the group s compliance with its code of conduct and on the employee concerns programme (OpenTalk) as it relates to non-financial issues.

Information

The committee receives information and reports from the safety and operations function, internal and external sources, including internal audit and the group compliance and ethics function. Staff from Ernst & Young attend if appropriate to a particular business or activity review.

Like BP s other board committees, SEEAC can access independent advice and counsel if it requires, on an unrestricted basis. The wider board is kept informed of the activities of the committee and any issues that have arisen through the regular update given by the SEEAC chair after each meeting.

Training and induction

Members of the committee receive ongoing training to assist them in carrying out their duties and an induction programme was provided for Mrs Carroll on joining the committee.

To develop a deeper understanding of BP s business and operations, Sir William Castell undertook a number of private briefings and several site visits on becoming SEEAC chairman. These visits included the Texas City refinery, where progress in implementing the recommendations of the Panel was observed and to the North Sea ETAP platforms where safety, operational and environmental management on an offshore production facility were reviewed.

Committee activities in 2008

The chart at the end of this section shows how SEEAC allocated its agenda time in 2008.

BP board performance report

Safety and operations
The group operations risk committee (GORC) was formed at the end of 2006 and is an executive level committee, chaired by the group chief executive. The GORC made regular reports to SEEAC during the year, including progress on the group-wide implementation of the operating management system (OMS) and BP s six-point plan, the development and utilization of the process safety index and statistics relating to the group s safety and operational performance.

L Duane Wilson was appointed by the board in 2007 as an independent expert to provide an objective assessment of BP s progress in implementing the Panel recommendations, aimed at improving process safety performance at BP s five US refineries. Mr Wilson, who was a member of the Panel, reports to the chairman of SEEAC and is independently funded through the company secretary s office.

Mr Wilson attended six meetings of the committee during 2008 and a private meeting with the committee during the year without the presence of executive management. Topics discussed included a presentation on his detailed work plan and progress updates. In May 2008, Mr Wilson published his first annual report where he assessed BP s progress against the 10 Panel recommendations. The report noted that while significant progress had been made, areas for improvement still remained. Further information on the report is available on BP s website.

Regional reviews and site visits
During the year, the committee reviewed reports on Alaska, the BTC pipeline, shipping and TNK-BP. The committee visited BP s refinery operations in Rotterdam, and coal bed methane operations in Durango, Colorado. In addition, some members visited the BP solar manufacturing facilities in Maryland and the group s operations in Azerbaijan.

Other topics
Other topics reviewed by the committee during the year included business continuity and crisis management, environmental requirements for new projects, results from a survey on safety culture in BP s US refineries and a report from the US ombudsman on concerns raised by employees in Alaska. The committee also received and discussed quarterly reports from the general auditor and the group compliance and ethics officer.

SEEAC 2008 Activities

Approximate allocation of agenda time*

Performance evaluation and forward agenda
The committee undertakes an annual review of its performance and process. In 2008, the review involved interviews with each committee member, with the results discussed at the committee s November meeting. Conclusions from the evaluation included noting the helpful insight gained from site visits and the value to the committee of the knowledge and expertise of the independent expert in respect of safety in the US refineries. The committee also reviewed its forward agenda for 2009.

SEEAC plans to meet seven times during 2009.

Remuneration committee report

Membership
The committee consists solely of non-executive directors who are considered by the board to be independent.

Members of the remuneration committee during the year were Dr DeAnne Julius (chairman), Erroll Davis, Jr, Sir Tom McKillop and Sir Ian Prosser. The chairman of the board also attends meetings of the committee.

Attendance
The committee met six times during 2008.

	Remuneration committee meetings eligible to attend	Remuneration committee meetings attended

Dr D S Julius (Chair)	6	6
E B Davis, Jr	6	5
Sir Tom McKillop	6	6
Sir Ian Prosser	6	6
P D Sutherland	6	6

Role and authority of the committee

The committee determines, on behalf of the board, the terms of engagement and remuneration of the group chief executive, the chairman and executive directors and reports on those to shareholders. The committee is independently advised.

Further details on the committee s role, authority and activities during the year are set out in the directors remuneration report, which is the subject of a vote by shareholders at the 2009 AGM.

The remuneration committee plans to meet five times in 2009.

Chairman s committee report

Membership

The committee consists of the chairman and all non-executive directors.

Attendance

The committee met four times during 2008.

	Chairman s committee meetings eligible to attend	Chairman s committee meetings attended
P D Sutherland	4	4
Sir Ian Prosser	4	4
A Burgmans	4	4
C B Carroll	4	3
Sir William Castell	4	4
G David	2	2
E B Davis, Jr	4	4
D J Flint	4	4
Dr D S Julius	4	4
Sir Tom McKillop	4	4
Dr W E Massey (former member)	2	2

BP board performance report

Role and authority of the committee

The main tasks and requirements for the committee are set out in the principles and are:

Evaluating the performance and effectiveness of the group chief executive;

Reviewing the structure and effectiveness of the business organization of BP;

Reviewing the systems for senior executive development and determining the succession plan for the group chief executive, executive directors and other senior members of executive management;

Determining any other matter that is appropriate to be considered by all of the non-executive directors;

Opining on any matter referred to it by the chairman of any committee comprised solely of non-executive directors.

Committee activities

The chairman s committee considered aspects of a number of strategic issues including the relationship with the company s partners in TNK-BP. The committee has reviewed with Dr Hayward the short- and long-term challenges facing the group. Dr Hayward has kept the committee briefed on the implementation of the forward agenda and its implications for the evolution of the executive team and succession within the leadership cadre. The committee has also reviewed the steps taken by Dr Hayward to refine the corporate culture and the values within BP. There have been active discussions around the tone from the top .

The committee has reviewed the performance of the chairman and Dr Hayward.

The chairman s committee plans to meet four times in 2009.

Nomination committee report

Membership

The committee s members nominally consist of the chairman and the chairs of SEEAC, audit and remuneration committees.

Members of the nomination committee during the year were Peter Sutherland (chairman), Dr DeAnne Julius, Sir Ian Prosser and Dr Walter Massey. Dr Massey remained a member of the nomination committee during the year after his retirement from the board to assist in the search for a successor to BP s chairman. Sir William Castell has now joined the committee.

Attendance

The committee met six times during 2008.

	Nomination committee meetings eligible to attend	Nomination committee meetings attended
P D Sutherland (chairman)	6	6
Dr D S Julius	6	6
Dr W E Massey	6	6
Sir Ian Prosser	6	6

Role and authority of the committee

The main tasks and requirements for the committee are set out in the principles and are:

Identifying, evaluating and recommending candidates for appointment or reappointment as directors.

Identifying, evaluating and recommending candidates for appointment as company secretary.

Keeping under review the mix of knowledge, skills and experience of the board to ensure the orderly succession of directors.

Reviewing the outside directorship/commitments of the non-executive directors.

Committee activities

During 2008 the primary work of the committee has been the continuation of the process to select a successor to Mr Sutherland who is to stand down as chairman.

For this purpose, Sir Ian Prosser, as Senior Independent Director, has chaired the committee. The committee has been assisted in this task by Dr Anna Mann of MWM Consulting LLP. The committee has adopted a robust process. Key strategic issues facing BP for the coming years were identified through discussions with individual board members. From these discussions a role description was developed. This formed the basis of a worldwide search from which in excess of 30 candidates emerged. This broad group has been refined and the process is continuing. The board has been regularly briefed on the work of the committee.

As part of the chairman selection process, potential candidates for non-executive directors roles have been revealed. The committee will continue actively to keep the skills of the board under review and pursue its refreshment.

BP board performance report

Directors interests

Current directors	At 31 Dec 2008	At 1 Jan 2008	Change from 31 Dec 2008 to 18 Feb 2009
A Burgmans	10,000	10,000	
C B Carroll			
Sir William Castell	82,500	50,000	
I C Conn	240,789[a]	229,969[a]	39,148
G David	9,000[b]	[c]	
E B Davis, Jr	73,185[b]	70,602[b]	
D J Flint	15,000	15,000	
Dr B E Grote	1,214,330[d]	1,193,137[d]	47,334
Dr A B Hayward	488,459	482,398	39,148
A G Inglis	226,175[e]	224,006[e]	29,249
Dr D S Julius	15,000	15,000	
Sir Tom McKillop	20,000	20,000	
Sir Ian Prosser	16,301	16,301	
P D Sutherland	30,906	30,906	

Directors leaving the board in 2008	At resignation/retirement	At 1 Jan 2008
Dr D C Allen (retired 31 March 2008)	597,568[f]	597,568[f]
Dr W E Massey (retired 17 April 2008)	49,722[b]	49,722[b]

[a]Includes 44,158 shares held as ADSs at 31 December 2008 and 41,692 shares held as ADSs at 1 January 2008.

[b]Held as ADSs.

[c]On appointment at 11 February 2008.

[d]Held as ADSs, except for 94 shares held as ordinary shares.

[e]Includes 34,962 shares held as ADSs.

[f]Includes 25,368 shares held as ADSs.

The above figures indicate and include all the beneficial and non-beneficial interests of each director of the company in shares of the company (or calculated equivalents) that have been disclosed to the company under the Disclosure and Transparency Rules and Companies Acts 1985 or 2006 (as the case may be) as at the applicable dates. The above figures do not include share options granted or interests in performance shares that have yet to vest. Details of these are set out in full in the directors remuneration report on pages 79 and 80.

Executive directors are also deemed to have an interest in such shares of the company held from time to time by the BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company s option schemes.

No director has any interest in the preference shares or debentures of the company or in the shares or loan stock of any subsidiary company.

Directors remuneration report

Directors remuneration report

Part 1 Summary

BP executives delivered a strong performance in a turbulent environment during 2008 and restored the group s operations to a high standard after several years of focused effort. We commend them for a job well done.

Key financial targets for the year were exceeded, even after adjusting for the effect of high oil prices during part of the year. Safe and reliable operations remained at the top of the agenda and key safety metrics and milestones were achieved. The year s results were especially strong in Exploration and Production, with the start-up of the Thunder Horse platform and excellent overall reserves replacement. Key targets were also met in Refining and Marketing and both the Texas City and Whiting refineries were safely restored to full capacity by the end of the year. The annual bonus results, set out in the table opposite, reflect this strong performance and determined leadership.

The committee undertook a detailed review of BP s underlying performance against competitors in determining the 2006-2008 share element vesting under the executive directors incentive plan (EDIP). This review included financial measures such as earnings per share, returns on average capital employed, free cash flow, operating measures for both Exploration and Production and Refining and Marketing, and non-financial measures for safety and reputation. All measures were compared across competitors and showed BP firmly in the pack of the other European oil majors. The comparison of total shareholder return (TSR) was less favourable to BP, partly due to exchange rate movements and turbulence in the financial markets. After careful review, the committee concluded that TSR alone was not a fair reflection of underlying performance over the 2006-2008 period. We concluded that it was appropriate to approve the vesting of 15% of the shares in the plan for the current directors. This too is set out in the table opposite.

Salaries were increased mid-2008 after our normal review. For 2009, we have agreed with the group chief executive s view that salaries should be frozen at their current level. There also will be no change in the target and normal maximum levels of bonus for 2009. The group chief executive s and group chief financial officer s bonuses will be based 70% on group performance against key metrics in the annual plan, 15% on safety performance and 15% on people. The chief executives of Exploration and Production and Refining and Marketing will have 50% of their bonuses determined on the above basis and 50% on the performance of their respective businesses.

The EDIP share element will again provide the long-term component of remuneration for the 2009-2011 period, with some slight modifications. First, reflecting its recent growth, ConocoPhillips will be added to the peer group of comparators (currently ExxonMobil, Shell, Total and Chevron). Second, to provide a more balanced assessment, vesting will be based half on BP s total shareholder return relative to the peer group and half on underlying performance compared with this same peer group. BP s performance will be compared on an interpolated basis relative to the performance of the other five. As in previous years, shares will vest at 100%, 70% and 35% for performance equivalent to first, second and third rank respectively and none for fourth or fifth.

We remain committed to a remuneration policy and practice that aligns with the long-term interests of shareholders and provides an appropriate reward for talented and committed executives. In the current volatile climate, executive leadership is more important than ever. The committee will continue to use careful and rigorous judgement in assessing performance, and to communicate our assessment in a clear way to shareholders.

Dr DeAnne S Julius
Chairman, Remuneration Committee
24 February 2009

Directors remuneration report

Summary of remuneration of executive directors in 2008[a]

	Annual remuneration								Long-term remuneration Share element of EDIP[b]				
									2005-2007 plan (vested in Feb 2008)		**2006-2008 plan (vested in Feb 2009)**		2008-2010 plan
	Salary (thousand)		Annual performance bonus (thousand)		Non-cash benefits and other emoluments (thousand)		Total (thousand)		Actual shares vested	Value (thousand)	Actual[c] shares vested	Value[d] (thousand)	Potential maximum performance shares[e]
	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**					
Dr A B Hayward	£877	**£998**	£1,262	**£1,496**	£14	**£15**	£2,153	**£2,509**	0	0	66,136	£336	845,319
I C Conn	£581	**£670**	£698	**£871**	£45	**£45**	£1,324	**£1,586**	0	0	66,136	£336	578,376
Dr B E Grote	$1,175	**$1,340**	$1,551	**$1,742**	$10	**$8**	$2,736	**$3,090**	0	0	80,231[f]	$603	581,748
A G Inglis	£556	**£670**	£800	**£1,173**	£188	**£ 212**[g]	£1,544	**£2,055**	0	0	54,994	£279	578,376
Directors leaving the board in 2008													
Dr D C Allen[h]	£500	**£128**	£539	**£163**	£13	**£3**	£1,052	**£294**	0	0	34,518	£175	n/a

Amounts shown are in the currency received by executive directors. Annual bonuses are shown in the year they were earned.

[a]This information has been subject to audit.

[b]Or equivalent plans in which the individual participated prior to joining the board.
[c]Includes shares representing reinvested dividends received on the shares that vested at the end of the performance period.

[d]Based on market price on vesting date (£5.08 per share/$45.13 per ADS).

[e]Maximum potential shares that could vest at the end of the three-year period depending on performance.

[f]Dr Grote holds shares in the form of ADSs. The above number reflects calculated equivalent in ordinary shares.

[g]This amount includes costs of London accommodation provided to Mr Inglis. In addition, under a tax equalization arrangement, BP also discharged a US tax liability arising on his participation in the UK pension scheme amounting to $553,175.

[h]Dr Allen resigned from the board on 31 March 2008. In addition to the above, he was awarded compensation for loss of office equal to one year s salary (£510,000). He also received £30,000 in respect of statutory rights and retained his company car.

Pensions

All executive directors are part of a final salary pension scheme. Accrued annual pension earned as at 31 December 2008 is £561,000 for Dr Hayward, £264,000 for Mr Conn, $868,000 for Dr Grote and £326,000 for Mr Inglis.

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years, relative to the FTSE 100 Index (of which the company is a constituent). The values of the hypothetical £100 holdings at the end of the five-year period were £144.36 and £115.05 respectively.

Remuneration of non-executive directors in 2008[a]

		£ thousand
	2007	**2008**
A Burgmans	86	**90**
Sir William Castell	87	**108**
C B Carroll	43	**93**
G David[b]	n/a	**100**
E B Davis, Jr	107	**105**
D J Flint	86	**90**
Dr D S Julius	106	**110**
Sir Tom McKillop	87	**95**
Sir Ian Prosser	137	**170**
P D Sutherland	517	**600**
Directors leaving the board in 2008		
Dr W E Massey[c]	133	**90**

[a] This information has been subject to audit.

[b] Appointed on 11 February 2008.

[c] Also received a superannuation gratuity of £23,000.

In 2008 the board, after a review, determined that in future it would continue to set the remuneration of the non-executive directors. However, in the case of the chairman this would be based on a recommendation from the remuneration committee and, for the non-executive directors, it would be based on a recommendation from the chairman.

This process was adopted in 2008 and recommendations were made. However, the chairman and the non-executive directors informed the board that, in the current economic circumstances, they did not wish to receive any increase in remuneration for 2009. The board accordingly maintained the fees at the 2008 level for 2009 save that no committee membership fee would in future be paid to members of the nomination committee.

Directors remuneration report

Part 2 Executive directors remuneration

2008 remuneration

Salary increases

As part of our normal cycle, salaries were reviewed mid-year and were increased to reflect market competitiveness and personal performance. Dr Hayward s salary was increased 10% to £1,045,000, and the other executive directors by 6% to the following: Mr Conn £690,000, Dr Grote $1,380,000 and Mr Inglis £690,000.

Annual bonus result

Performance measures and targets were set at the beginning of the year based on the annual plan. The target level bonus of 120% of base salary placed 50% on group financial and operating results including earnings before interest, taxes, depreciation and amortization (EBITDA), cash costs, cash flow, return on average capital employed (ROACE) and capital expenditure. The remaining portion was weighted 25% on safety, 25% on people and 20% on individual performance, principally operating results and leadership.

Overall performance for 2008 was very strong and is more fully set out in other parts of this report. Financial results exceeded targets for EBITDA, free cash flow and returns on average capital employed, even after adjusting for the high oil prices for part of the year. Cash costs were managed below target, and capital expenditure within expected levels.

Operationally, the upstream business had an excellent year, replacing a high proportion of proved reserves, exceeding its production target and successfully starting up the important Thunder Horse development in the Gulf of Mexico. The downstream business successfully and safely completed the full re-commissioning of the Texas City and Whiting refineries and improved overall performance. Alternative Energy exceeded its targets for wind and met its solar sales target.

Safe and reliable operations remained at the top of the agenda and performance, both in terms of safety metrics and progress on OMS implementation, was assessed as satisfactory by the safety, ethics and environment assurance committee (SEEAC). On the people front, significant progress was made in reducing complexity and embedding a performance culture throughout the group.

Annual bonus results for 2008 reflect this overall strong performance and committed leadership and are set out in the table on page 75.

2006-2008 share element result

Performance for the share element is assessed relative to the TSR of the company compared with the other oil majors ExxonMobil, Shell, Total and Chevron. Recognizing the inherent imperfections in a TSR ranking, the EDIP rules give the committee power to adjust (upwards or downwards) the vesting level derived from the TSR ranking if it considers that the ranking does not fairly reflect BP s underlying business performance relative to the comparators. This is designed to enable a more comprehensive review of BP s long-term performance, with the aims of tempering anomalies created by relying solely on a formula-based approach.

For the 2006-2008 plan, BP was fifth relative to the other majors in terms of TSR when calculated on a common currency (US dollar) basis as originally anticipated. However, unusually large currency movements at the end of this period were an extraneous influence on this result. On a local currency basis, the TSRs of BP, Shell and Total were tightly bunched together. The committee also reviewed BP s underlying business performance relative to the comparator companies over the full three-year period. This review included financial measures (earning per share growth, ROACE, free cash flow, net income), operating measures (production, reserves replacement and Refining and Marketing profitability), and non-financial measures (health, safety and environmental and reputation). Again, the performance of the European comparators was quite similar: BP led the group on some measures (notably free cash flow and reserves replacement) but lagged on Refining and Marketing profitability.

The committee concluded that the TSR result, by itself, was not a fair reflection of BP s relative underlying performance over the period. After thorough consideration, the committee determined that 15% of the shares under the 2006-08 award should vest this being a fair reflection of the overall results achieved and consistent with its approach to the clustering of results, as anticipated in the EDIP rules approved by shareholders in 2005.

In accordance with its powers under the EDIP rules, the committee also determined that, as there was clear evidence of a progressive turnaround of performance over the final 18 months of the performance period, individual vesting levels should only occur to the extent that eligible individuals contributed to the turnaround. The resulting final vesting for all eligible participants is shown in the table on page 79.

Mr Inglis s award was made prior to his appointment as an executive director under the MTPP (medium term performance plan) that is the comparable plan to the EDIP. Vesting conditions were the same as for the EDIP for Mr Inglis but, unlike the EDIP, the MTPP does not have a three-year retention period.

Lord Browne also held an award under the 2006-08 share element related to long-term leadership measures. These focused on sustaining BP s financial, strategic and organizational health. Performance relative to the award was assessed by the chairman s committee and, based on this assessment, no shares were vested.

Remuneration policy

Our remuneration policy for executive directors aims to ensure there is a clear link between the company s purpose, its business plans and executive reward, with pay varying with performance. In order to achieve this, the policy is based on these key principles:

- The majority of executive remuneration will be linked to the achievement of demanding performance targets, independently set to support the creation of long-term shareholder value.

- The structure will reflect a fair system of reward for all the participants.

- The remuneration committee will determine the overall amount of each component of remuneration, taking into account the success of BP and the competitive environment.

- There will be a quantitative and qualitative assessment of performance, with the remuneration committee making an informed judgement within a framework approved by shareholders.

- Remuneration policy and practice will be as transparent as possible.

- Executives will develop a significant personal shareholding in order to align their interests with those of shareholders.

- Pay and employment conditions elsewhere in the group will be taken into account, especially in setting annual salary increases.

- The remuneration policy for executive directors will be reviewed regularly, independently of executive management, and will set the tone for the remuneration of other senior executives.

- The remuneration committee will actively seek to understand shareholder preferences.

Executive directors total remuneration consists of salary, annual bonus, long-term incentives, pensions and other benefits. The remuneration committee reviews this structure regularly to ensure it is achieving its aims. In 2008, over three-quarters of executive directors total potential remuneration was performance related. The same will be true for total potential remuneration in 2009.

Directors remuneration report

Salary

The remuneration committee normally reviews salaries annually, taking into account other large Europe-based global companies and companies in the US oil and gas sector. These groups are each defined and analyzed by the committee s independent remuneration advisers. For 2009, the committee has agreed with the group chief executive s view that salaries should be frozen at their current level.

Annual bonus

All executive directors are eligible to take part in an annual performance-based bonus scheme. The remuneration committee sets bonus targets and levels of eligibility each year.

The target level for 2009 is 120% of base salary. In normal circumstances, the maximum payment for substantially exceeding performance targets will continue to be 150% of base salary.

The group chief executive s and group chief financial officer s bonus will be determined on group results as follows:

- 70% on group performance compared with key metrics and milestones from the annual plan including:
  - Cash costs and organic capex.
  - Underlying replacement cost profit and operating cash flow.
  - Production and reserves replacement.
  - Refining availability and earnings/barrel.
  - Installed wind capacity.
- 15% on safety performance, including satisfactory and improving key metrics as well as progress on OMS implementation.
- 15% on people, including behaviour, culture and values.

For the chief executive of Exploration and Production, and the chief executive of Refining and Marketing, 50% of their bonus will be based on the above group results and 50% on the results of their respective businesses as measured by key metrics and milestones set out in the annual plan. For Exploration and Production, these include production costs and reserves replacement as well as safety and new opportunities. For Refining and Marketing, they include refining availability, earnings and cash costs, as well as safety and work simplification.

The remuneration committee will also review carefully the underlying performance of the group in light of company business plans and will look at competitors results, analysts reports and the views of the chairmen of other BP board committees when assessing results.

In exceptional circumstances, the remuneration committee can decide to award bonuses moderately above the maximum level. The committee can also decide to reduce bonuses where this is warranted and, in exceptional circumstances, bonuses could be reduced to zero. We have a duty to shareholders to use our discretion in a reasonable and informed manner, acting to promote the success of the company, and also to be accountable and transparent in our decisions. Any significant exercise of discretion will be explained in the subsequent directors remuneration report.

Long-term incentives

Each executive director participates in the EDIP. It has three elements: shares, share options and cash. The remuneration committee does not intend to use either the share option or cash elements in 2009, nor to grant any retention awards which are also permitted under the EDIP. We intend that executive directors will continue to receive performance shares under the EDIP, barring unforeseen circumstances, until it expires or is renewed in 2010.

Policy for performance share awards

The remuneration committee can award shares to executive directors that will only vest to the extent that demanding performance conditions are satisfied at the end of a three-year period. The maximum number of these performance shares that can be awarded to an executive director in any year is at the discretion of the remuneration committee, but will not normally exceed 5.5 times base salary.

In exceptional circumstances, the committee also has an overriding discretion to reduce the number of shares that vest or to decide that no shares vest.

The compulsory retention period will also be decided by the committee and will not normally be less than three years. Together with the performance period, this gives executive directors a six-year incentive structure, as shown in the timeline below, which is designed to ensure their interests are aligned with those of shareholders.

Where shares vest, the executive director will receive additional shares representing the value of the reinvested dividends.

The committee s policy continues to be that each executive director build a significant personal shareholding, with a target of shares equivalent in value to five times his or her base salary within a reasonable timeframe from appointment as an executive director. This policy is reflected in the terms of the performance shares under the EDIP, as shares vested will normally only be released at the end of the three-year retention period, described above, if these minimum shareholding guidelines are met.

Performance conditions

Performance conditions for the 2009-11 share element will be somewhat modified from previous years. First, the peer group of oil majors against which we compare will be increased to include ConocoPhillips as well as ExxonMobil, Shell, Total and Chevron as previously. This change reflects ConocoPhillips significant growth over the last few years, providing it with similar scale and global reach to the other oil majors.

Second, vesting of the shares will be based 50% on total shareholder return (TSR) versus the competitor group and 50% on a balanced scorecard of underlying performance versus the same competitors. The underlying performance will be assessed on three measures reflecting key priorities in BP s strategy in Exploration and Production, hydrocarbon production growth, in Refining and Marketing, improvement in earnings per barrel, and group increase in underlying net income. Both Exploration and Production production growth and Refining and Marketing earnings improvement are key strategic objectives for the group and this inclusion aligns key measures with both executive director priorities as well as key drivers of value for shareholders. Group increase in underlying net income acts as a holistic measure of success reflecting revenues, costs and complexity as well as safe and reliable operations.

Directors remuneration report

All the above measures will be compared with the five other oil majors to determine the overall vesting result. The methodology used will rank each of the five other majors on each of the measures. BP s performance will then be compared on an interpolated basis relative to the performance of the other five. For performance between second and third or first and second, the result will be interpolated based on BP s performance relative to the company ranked directly above and below it. As in previous years, performance shares will vest at 100%, 70% and 35% for performance equivalent to first, second and third rank respectively and none for fourth or fifth place. The three underlying measures will be averaged to form the balanced scorecard component.

The committee considers that this combination of measures provides a good balance of external as well as internal metrics reflecting both shareholder value and operating priorities. As in previous years, the committee will exercise its discretion, in a reasonable and informed manner to adjust vesting levels upwards or downwards if it concludes the above quantitative approach does not reflect the true underlying health and performance of BP s business relative to its peers. It will explain any adjustments in the next directors remuneration report following the vesting, in line with its commitment to transparency.

Pensions

Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries. Additional details are given in the table below.

UK directors

UK directors are members of the regular BP Pension Scheme. The core benefits under this scheme are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, up to a maximum of two-thirds of final basic salary and a dependant s benefit of two-thirds of the member s pension. The scheme pension is not integrated with state pension benefits.

The rules of the BP Pension Scheme were amended in 2006 such that the normal retirement age is 65. Prior to 1 December 2006, scheme members could retire on or after age 60 without reduction. Special early retirement terms apply to pre-1 December 2006 service for members with long service as at 1 December 2006.

Pension benefits in excess of the individual lifetime allowance set by legislation are paid via an unapproved, unfunded pension arrangement provided directly by the company.

Although Mr Inglis is, like other UK directors, a member of the BP Pension Scheme, he is currently based in Houston, US. His participation in the BP Pension Scheme gives rise to a US tax liability. During 2008, the committee approved the discharge of this US tax liability under a tax equalization arrangement in respect of the period since Mr Inglis became a director in February 2007, amounting to $553,175.

US directors

Dr Grote participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. Pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, consistent with US tax regulations as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level. The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (and as specified under the qualified arrangement), multiplied by years of service. There is an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is eligible to participate under the supplemental plan. His pension accrual for 2008, shown in the table below, includes the total amount that could become payable under all plans.

Other benefits

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share saving schemes and savings plans applying in their home countries. Benefits in kind are not pensionable. Expatriates may receive a resettlement allowance for a limited period.

As Mr Inglis is currently based in Houston, US, BP provides accommodation in London.

Pensions[a]

thousand

	Service at 31 Dec 2008	Accrued pension entitlement at 31 Dec 2008	Additional pension earned during the year ended 31 Dec 2008[b]	Transfer value of accrued benefit[c] at 31 Dec 2007 (A)	Transfer value of accrued benefit[c] at 31 Dec 2008 (B)	Amount of B-A less contributions made by the director in 2008
Dr A B Hayward (UK)	27 years	£561	£72	£7,986	£8,045	£9
I C Conn (UK)	23 years	£264	£26	£3,375	£3,161	(£214)
Dr B E Grote (US)	29 years	$868	$45	$7,901	$11,220	$2,860
A G Inglis (UK)	28 years	£326	£30	£4,613	£4,399	(£214)
Directors leaving the board in 2008						
Dr D C Allen (UK)[d]	n/a	£260	£12	£4,256	£5,580	£1,324

[a]This information has been subject to audit.

[b]Additional pension earned during the year includes an inflation increase of 4.0% for UK directors and 5.8% for US directors.

[c]Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.

[d]Dr D C Allen retired on 31 March 2008 and commuted part of his pension for a lump sum. The figures above make no allowance for the payment of this lump sum. If allowance is made (in line with the strict requirements of the regulations), and the transfer value at the end of the year is based on the pension in payment at that time, then the transfer value at 31 December 2008 would be £4.55 million and the change in value over the year would be £0.29 million.

Directors remuneration report

Share element of EDIP[a]

				Share element interests			Interests vested in 2008 and 2009		
				Potential maximum performance shares[b]					
	Performance period	Date of award of performance shares	Market price of each share at date of award of performance shares £	At 1 Jan 2008	Awarded 2008	At 31 Dec 2008	Number of ordinary shares vested[c]	Vesting date	Market price of each share at vesting £
Dr A B Hayward	2005-2007	28 Apr 2005	5.33	436,623			0	n/a	n/a
	2006-2008	**16 Feb 2006**	**6.54**	**383,200**		**383,200**	**66,136**	**6 Feb 2009**	**5.08**
	2007-2009	06 Mar 2007	5.12	706,311		706,311			
	2008-2010	13 Feb 2008	5.61		845,319	845,319			
I C Conn	2005-2007	28 Apr 2005	5.33	415,832			0	n/a	n/a
	2006-2008	**16 Feb 2006**	**6.54**	**383,200**		**383,200**	**66,136**	**6 Feb 2009**	**5.08**
	2007-2009	06 Mar 2007	5.12	456,748		456,748			
	2008-2010	13 Feb 2008	5.61		578,376	578,376			
	2008-2011[d]	13 Feb 2008	5.61		133,452	133,452			

	2008-2013[d]	13 Feb 2008	5.61		133,452	133,452			
Dr B E Grote[e]	2005-2007	28 Apr 2005	5.33	501,782			0	n/a	n/a
	2006-2008	**16 Feb 2006**	**6.54**	**470,432**		**470,432**	**80,231**	**6 Feb 2009**	**5.08**
	2007-2009	06 Mar 2007	5.12	491,640		491,640			
	2008-2010	13 Feb 2008	5.61		581,748	581,748			
A G Inglis	2005-2007	8 Mar 2005	5.70	209,000			0	n/a	n/a
	2006-2008	**27 Mar 2006**	**6.59**	**325,750**		**325,750**	**54,994**	**6 Feb 2009**	**5.08**
	2007-2009	06 Mar 2007	5.12	400,243		400,243			
	2008-2010	13 Feb 2008	5.61		578,376	578,376			
	2008-2011[d]	13 Feb 2008	5.61		133,452	133,452			
	2008-2013[d]	13 Feb 2008	5.61		133,452	133,452			
Directors leaving the board in 2008									
Dr D C Allen	2005-2007	28 Apr 2005	5.33	436,623			0	n/a	n/a
	2006-2008	**16 Feb 2006**	**6.54**	**383,200**		**383,200**	**34,518**	**6 Feb 2009**	**5.08**
	2007-2009	06 Mar 2007	5.12	456,748		456,748			

Former directors

Lord Browne	2005-2007	28 Apr 2005	5.33	2,006,767		90,232	6 Feb 2008	5.45
	2006-2008	**16 Feb 2006**	**6.54**	**1,761,249**	**1,761,249**	**0**	**n/a**	**n/a**
J A Manzoni	2005-2007	28 Apr 2005	5.33	436,623		0	n/a	n/a
	2006-2008	**16 Feb 2006**	**6.54**	**383,200**	**383,200**	**0**	**n/a**	**n/a**

[a]This information has been subject to audit. Includes equivalent plans in which the individual participated prior to joining the board.
[b]BP s performance is measured against the oil sector. For the 2005-2007 and subsequent awards, the performance condition is TSR measured against ExxonMobil, Shell, Total and Chevron. Each performance period ends on 31 December of the third year.
[c]Represents awards of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares awarded.
[d]Restricted award under share element of EDIP. As reported in the 2007 directors remuneration report in February 2008, the committee awarded both Mr Inglis and Mr Conn restricted shares, as set out above.
These one-off awards will vest on the third and fifth anniversary of the award, dependent on the remuneration committee being satisfied as to their personal performance at the date of vesting. Any unvested tranche will lapse in the event of cessation of employment with the company.
[e]Dr Grote receives awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares.

Directors remuneration report

Share options[a]

	Option type	At 1 Jan 2008	Granted	Exercised	At 31 Dec 2008	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Dr A B Hayward	SAYE	3,220			3,220	£5.00		01 Sep 2011	29 Feb 2012
	EXEC	34,000			34,000	£5.99		15 May 2003	15 May 2010
	EXEC	77,400			77,400	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	160,000			160,000	£5.72		18 Feb 2005	18 Feb 2012
	EDIP	220,000			220,000	£3.88		17 Feb 2004	17 Feb 2010
	EDIP	275,000			275,000	£4.22		25 Feb 2005	25 Feb 2011
I C Conn	SAYE	1,456		1,456		£3.50	£4.72[b]	01 Sep 2008	28 Feb 2009
	SAYE	1,186			1,186	£3.86		01 Sep 2009	28 Feb 2010
	SAYE	1,498			1,498	£4.41		01 Sep 2010	28 Feb 2011
	SAYE		617		617	£4.87		01 Sep 2011	01 Feb 2012
	EXEC	72,250			72,250	£5.67		23 Feb 2004	23 Feb 2011
	EXEC	130,000			130,000	£5.72		18 Feb 2005	18 Feb 2012
Dr B E Grote[c]	BPA	10,404			10,404	$53.90		15 Mar 2000	14 Mar 2009
	BPA	12,600			12,600	$48.94		28 Mar 2001	27 Mar 2010
	EDIP	40,182		40,182		$49.65	$65.58-$66.50	19 Feb 2002	19 Feb 2008
	EDIP	58,173			58,173	$48.82		18 Feb 2003	18 Feb 2009

	EDIP	58,173	58,173	$37.76	17 Feb 2004	17 Feb 2010
	EDIP	58,333	58,333	$48.53	25 Feb 2005	25 Feb 2011
A G Inglis	SAYE	4,550	4,550	£3.50[d]	01 Sep 2008	28 Feb 2009
	EXEC	72,250	72,250	£5.67	23 Feb 2004	22 Feb 2011
	EXEC	119,000	119,000	£5.72	18 Feb 2005	17 Feb 2012
	EXEC	119,000	119,000	£3.88	17 Feb 2006	16 Feb 2013
	EXEC	100,500	100,500	£4.22	25 Feb 2007	24 Feb 2014
Directors leaving the board in 2008						
Dr D C Allen	EXEC	37,000	37,000[e]	£5.99	15 May 2003	15 May 2010
	EXEC	87,950	87,950[e]	£5.67	23 Feb 2004	23 Feb 2011
	EXEC	175,000	175,000[e]	£5.72	18 Feb 2005	18 Feb 2012
	EDIP	220,000	220,000[e]	£3.88	17 Feb 2004	17 Feb 2010
	EDIP	275,000	275,000[e]	£4.22	25 Feb 2005	25 Feb 2011

The closing market prices of an ordinary share and of an ADS on 31 December 2008 were £5.26 and $46.74 respectively.
During 2008, the highest market prices were £6.50 and $76.12 respectively and the lowest market prices were £3.76 and $39.56 respectively.
BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
EDIP = Executive Directors Incentive Plan adopted by shareholders in April 2005 as described on page 76.
EXEC = Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.
SAYE = Save As You Earn employee share scheme.

[a]This information has been subject to audit.
[b]Closing market price for information. Shares were retained when exercised.
[c]Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.
[d]Options exercised on 21 January 2009 and the shares were retained by Mr Inglis. Closing market price for information on that date was £4.86.
[e]On leaving the board on 31 March 2008.

Directors remuneration report

Service contracts

Director	Contract date	Salary as at 31 Dec 2008
Dr A B Hayward	29 Jan 2003	£1,045,000
I C Conn	22 Jul 2004	£690,000
Dr B E Grote	7 Aug 2000	$1,380,000
A G Inglis	1 Feb 2007	£690,000

Service contracts have a notice period of one year and may be terminated by the company at any time with immediate effect on payment in lieu of notice equivalent to one year s salary or the amount of salary that would have been paid if the contract had been terminated on the expiry of the remainder of the notice period. The service contracts are expressed to expire at a normal retirement age of 60 (subject to age discrimination).

Dr Grote s contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement of 7 August 2000, which expires on 31 March 2010. The secondment can be terminated by one month s notice by either party and terminates automatically on the termination of Dr Grote s service contract.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of the early termination of any of the contracts by the company, other than for cause (or under a specific termination payment provision), the relevant director s then-current salary and benefits would be taken into account in calculating any liability of the company.

Since January 2003, new service contracts include a provision to allow for severance payments to be phased, when appropriate. The committee will also consider mitigation to reduce compensation to a departing director, when appropriate to do so.

Director leaving the board in 2008

Dr Allen left the company at the end of March 2008. He was entitled to one year s salary (£510,000) as compensation in accordance with his contractual entitlement, as well as a pro rata bonus for 2008 and continued full participation in the 2006-08 and 2007-09 share elements, according to the normal rules of the plan.

Executive directors external appointments

The board encourages executive directors to broaden their knowledge and experience by taking up appointments outside the company. Each executive director is permitted to accept one non-executive appointment, from which they may retain any fee. External appointments are subject to agreement by the chairman and reported to the board. Any external appointment must not conflict with a director s duties and commitments to BP.

During the year, the fees received by executive directors for external appointments were as follows:

Executive director	Appointee company	Additional postion held at appointee company	Total fees
Dr A B Hayward	Tata Steel	Senior	£83,000

		Independent Director	
I C Conn	Rolls-Royce	Senior Independent Director	£65,000
Dr B E Grote	Unilever	Audit committee member	Unilever PLC £33,500 Unilever NV 48,625
A G Inglis	BAE Systems	Chair of Corporate Responsibility Committee	£86,754

Remuneration committee
All the members of the committee are independent non-executive directors. Throughout the year, Dr Julius (chairman), Mr Davis, Sir Tom McKillop and Sir Ian Prosser were members. The group chief executive was consulted on matters relating to the other executive directors who report to him and on matters relating to the performance of the company; neither he nor the chairman were present when matters affecting their own remuneration were discussed.

Tasks

The remuneration committee s tasks are:

To determine, on behalf of the board, the terms of engagement and remuneration of the group chief executive and the executive directors and to report on these to the shareholders.

To determine, on behalf of the board, matters of policy over which the company has authority regarding the establishment or operation of the company s pension scheme of which the executive directors are members.

To nominate, on behalf of the board, any trustees (or directors of corporate trustees) of the scheme.

To review the policies being applied by the group chief executive in remunerating senior executives other than executive directors to ensure alignment and proportionality.

To recommend to the board the quantum and structure of remuneration for the chairman.

Directors remuneration report

Constitution and operation
Each member of the remuneration committee is subject to annual re-election as a director of the company. The board considers all committee members to be independent (*see page 66*).

They have no personal financial interest, other than as shareholders, in the committee s decisions.

The committee met six times in the period under review. Mr Sutherland, as chairman of the board, attended all the committee meetings.

The committee is accountable to shareholders through its annual report on executive directors remuneration. It will consider the outcome of the vote at the AGM on the directors remuneration report and take into account the views of shareholders in its future decisions. The committee values its dialogue with major shareholders on remuneration matters.

Advice
Advice is provided to the committee by the company secretary s office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committee s secretary and independent adviser. Advice was also received from Mr Jackson, the company secretary.

The committee also appoints external advisers to provide specialist advice and services on particular remuneration matters. The independence of the advice is subject to annual review.

In 2008, the committee continued to engage Towers Perrin as its principal external adviser. Towers Perrin also provided limited ad hoc remuneration and benefits advice to parts of the group, principally changes in employee share plans and some market information on pay structures.

Freshfields Bruckhaus Deringer LLP provided legal advice on specific matters to the committee, as well as providing some legal advice to the group.

Ernst & Young reviewed the calculations on the financial-based targets that form the basis of the performance-related pay for executive directors, that is, the annual bonus and share element awards described on page 75, to ensure they met an independent, objective standard. They also provided audit, audit-related and taxation services for the group.

Part 3 Non-executive directors remuneration

Policy
Remuneration of the chairman and the non-executive directors continues to be set by the board. The process by which the board determines that remuneration was reviewed during the year with the result that:

The quantum and structure of the chairman s remuneration would be reviewed by the remuneration committee. The remuneration committee would then make a recommendation to the board but the chairman would not vote on his own remuneration; and

The quantum and structure of non-executive director remuneration would be reviewed by the chairman, with support and analysis provided by the company secretary. The chairman would then make a recommendation to the board but non-executive directors would not vote on their own remuneration.

The above changes came into effect for the 2008 review of remuneration.

The other elements of BP s non-executive director remuneration policy remain unchanged:

Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.

Remuneration of non-executive directors is set by the board and should be proportional to their contribution towards the interests of the company.

Remuneration practice should be consistent with recognized best-practice standards for non-executive directors remuneration.

Remuneration should be in the form of cash fees, payable monthly.

Non-executive directors should not receive share options from the company.

Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year s base fee, to be held directly or indirectly in a manner compatible with their personal investment activities, and any applicable legal and regulatory requirements.

Fee structure

The table below shows the current fee structure for non-executive directors:

	£ thousand
	Fee level
Chairman[a]	600
Deputy chairman[b]	120
Board member	75
Audit committee and SEEAC chairmanship fees[c]	30
Remuneration committee chairmanship fee[c]	20
Transatlantic attendance allowance	5
Committee membership fee[d]	5

[a] The chairman remains ineligible for committee chairmanship and membership fees or transatlantic attendance allowance, but has the use of a fully maintained office for company business, a chauffeured car and security advice.

[b] The role of deputy chairman is combined with that of senior independent director. The deputy chairman is still eligible for committee chairmanship fees and transatlantic attendance allowance plus any committee membership fees.

[c] Committee chairmen do not receive an additional membership fee for the committee they chair.

[d] For members of the audit, SEEAC and remuneration committees.

Directors remuneration report

Remuneration of non-executive directors in 2008[a]

		£ thousand
	2007	**2008**
A Burgmans	86	**90**
Sir William Castell	87	**108**
C B Carroll	43	**93**
G David[b]	n/a	**100**
E B Davis, Jr	107	**105**
D J Flint	86	**90**
Dr D S Julius	106	**110**
Sir Tom McKillop	87	**95**
Sir Ian Prosser	137	**170**
P D Sutherland	517	**600**
Director leaving the board in 2008		
Dr W E Massey[c]	133	**90**

[a] This information has been subject to audit.

[b] Appointed on 11 February 2008.

[c] Also received a superannuation gratuity of £23,000.

No share or share option awards were made to any non-executive director in respect of service on the board during 2008.

Non-executive directors have letters of appointment, which recognize that, subject to the Articles of Association, their service is at the discretion of shareholders. All directors stand for re-election at each AGM.

Review of chairman and non-executive director remuneration

The new process for the determination of non-executive remuneration, as described earlier, was operated during the year and recommendations were made. However, the chairman and the non-executive directors informed the board that, in the current economic circumstances, they did not wish to receive any increase in remuneration for the coming year 2009.

The board, therefore, decided after review to maintain fees for 2009 at the 2008 level set out in the fee structure table, save that the committee membership fee would no longer be paid to members of the nomination committee.

Superannuation gratuities

Until 2002, BP maintained a long-standing practice whereby non-executive directors who retired from the board after at least six years service were eligible for consideration for a superannuation gratuity. The board was, and continues to be, authorized to make such payments under the company s Articles of Association and the amount of the payment is determined at the board s discretion, having regard to the director s period of service as a director and other relevant factors.

In 2002, the board revised its policy with respect to superannuation gratuities so that:

Non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment.

While non-executive directors in service at 1 July 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

The board made a superannuation gratuity of £23,000 during the year to Dr Walter Massey, who retired in April 2008. This payment was in line with the policy arrangements agreed in 2002 and outlined above.

Non-executive directors of Amoco Corporation

Non-executive directors who were formerly non-executive directors of Amoco Corporation have residual entitlements under the Amoco Non-Employee Directors Restricted Stock Plan. Directors were allocated restricted stock in remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. The restricted stock will vest on the retirement of the non-executive director at the age of 70 (or earlier at the discretion of the board). Since the merger, no further entitlements have accrued to any director under the plan. The residual interests, as interests in a long-term incentive scheme, are set out in the table below, in accordance with the Directors Remuneration Report Regulations 2002.

	Interest in BP ADSs at 1 Jan 2008 and 31 Dec 2008[a]	Date on which director reaches age 70[b]
E B Davis, Jr	4,490	5 Aug 2014
Director leaving the board in 2008		
Dr W E Massey[c]	3,346	5 April 2008

[a] No awards were granted and no awards lapsed during the year. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.

[b] For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

[c] Dr Massey retired from the board on 17 April 2008. He had received awards of Amoco shares under the plan between 22 June 1993 and 28 April 1998 prior to the merger. These interests had been converted into BP ADSs at the time of the merger. In accordance with the terms of the plan, the board exercised its discretion over this award on 16 May 2008 and the shares vested on that date (when the BP ADS market price was $74.57) without payment by him.

Past directors

Mr Miles (who was a non-executive director of BP until April 2006) was appointed as a director and non-executive chairman of BP Pension Trustees Limited in October 2006 for a term of three years. During 2008, he received £150,000 for this role.

Dr Walter Massey (who retired as a non-executive director of BP in April 2008) remained a member of the nomination committee during the year to assist in the search for a successor to BP s chairman. Dr Massey received a total fee of £15,000 for this role in 2008. Dr Massey was also appointed to the BP America board in April 2008 for a term of two years. During 2008, he received US$93,500 for this role.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary, on 24 February 2009.

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Additional information
for shareholders

Additional information for shareholders

Share ownership

Directors and senior management

As at 18 February 2009, the following directors of BP p.l.c. held interests in BP ordinary shares of 25 cents each or their calculated equivalent as set out below:

I C Conn	279,937	1,815,940[a]	266,904[c]
Dr B E Grote	1,261,664	2,066,316[a]	
Dr A B Hayward	527,607	2,734,170[a]	
A G Inglis	255,424	1,759,435[a b]	266,904[c]
A Burgmans	10,000		
C B Carroll			
Sir William Castell	82,500		
G David	9,000		
E B Davis, Jr	73,185		
D J Flint	15,000		
Dr D S Julius	15,000		
Sir Tom McKillop	20,000		
Sir Ian Prosser	16,301		
P D Sutherland	30,906		

[a]Performance shares awarded under the BP Executive Directors Incentive Plan. These figures represent the maximum possible vesting levels. The actual number of shares/ADSs that vest will depend on the extent to which performance conditions have been satisfied over a three-year period.

[b]Also includes 325,750 performance shares awarded under the BP Medium Term Performance Plan, which represents the maximum possible vesting level. The actual number of shares that vest will depend on the extent to which performance conditions have been satisfied over a three-year period.

[c]Restricted share award under the BP Executive Directors Incentive Plan. These shares will vest in two equal tranches after three and five years, subject to the directors continued service and satisfactory performance.

As at 18 February 2009, the following directors of BP p.l.c. held options under the BP group share option schemes for ordinary shares or their calculated equivalent as set out below:

I C Conn	205,551
Dr B E Grote	1,186,098
Dr A B Hayward	769,620
A G Inglis	410,750

There are no directors or members of senior management who own more than 1% of the ordinary shares outstanding. At 18 February 2009, all directors and senior management as a group held interests in 4,308,712 ordinary shares or their calculated equivalent, 11,163,994 performance shares or their calculated equivalent and 3,281,964 options for ordinary shares or their calculated equivalent under the BP group share options schemes.

Additional details regarding the options granted and performance shares awarded can be found in the directors remuneration report on pages 79 and 80.

Employee share plans

The following table shows employee share options granted.

			options thousands
	2008	2007	2006
Employee share options granted during the year[a]	**8,063**	6,004	53,977

[a]For the options outstanding at 31 December 2008, the exercise price ranges and weighted average remaining contractual lives are shown in Financial statements Note 41 on page 166.

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and/or matching share plan arrangements. BP also uses long-term performance plans (*see Financial statements Note 41 on page 166*) and the granting of share options as elements of remuneration for executive directors and senior employees.

Shares acquired through the company s employee share plans rank pari passu with shares in issue and have no special rights, save as described below. For legal and practical reasons, the rules of these plans set out the consequences of a change of control of the company, and generally provide for options and conditional awards to vest on an accelerated basis.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan, under which employees save on a monthly basis over a three-year or five-year period towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro rated basis.

Additional information for shareholders

BP ShareMatch plans
These are matching share plans, under which BP matches employees own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries, the plan is run on an annual basis, with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP, all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Once shares have been awarded to an employee under the plan, the employee may instruct the trustee how to vote their shares.

Local plans
In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

The above share plans are indicated as being equity-settled. In certain countries, however, it is not possible to award shares to employees owing to local legislation. In these instances, the award will be settled in cash, calculated as the cash equivalent of the value to the employee of an equity-settled plan.

Cash plans
Cash-settled share-based payments/Stock Appreciation Rights (SARs)
These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR/restricted shares to the employee at the date of exercise/maturity.

Employee share ownership plans (ESOPs)
ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the Executive Directors Incentive Plan, the Medium-Term Performance Plan, the Long-Term Performance Plan, the Deferred Annual Bonus Plan and the BP ShareMatch plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Pending vesting, the ESOPs have independent trustees that have the discretion in relation to the voting of such shares. Until such time as the company s own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders equity (*see Financial statements Note 40 on page 164*). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2008, the ESOPs held 29,051,082 shares (2007 6,448,838 shares and 2006 12,795,887 shares) for potential future awards, which had a market value of $220 million (2007 $79 million and 2006 $142 million).

Pursuant to the various BP group share option schemes, the following options for ordinary shares of the company were outstanding at 18 February 2009:

Options outstanding (shares)	Expiry dates of options	Exercise price per share
323,378,846	2009-2016	5.7050-11.9210

More details on share options appear in Financial statements Note 41 on page 166.

Major shareholders and related party transactions

Register of members holding BP ordinary shares as at 31 December 2008

	Number of	Percentage of	Percentage of

Range of holdings	ordinary shareholders	total ordinary shareholders	total ordinary share capital
1-200	57,617	18.22	0.01
201-1,000	120,017	37.94	0.31
1,001-10,000	124,970	39.51	1.83
10,001-100,000	11,837	3.74	1.17
100,001-1,000,000	1,089	0.34	1.95
Over 1,000,000[a]	790	0.25	94.73
Totals	316,320	100.00	100.00

[a]Includes JP Morgan Chase Bank holding 27.48% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2008[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	73,569	53.88	0.50
201-1,000	38,781	28.40	2.16
1,001-10,000	22,656	16.59	7.12
10,001-100,000	1,505	1.10	3.04
100,001-1,000,000	23	0.02	0.47
Over 1,000,000[b]	2	0.01	86.71
Totals	136,536	100.00	100.00

[a]One ADS represents six 25 cent ordinary shares.

[b]One of the holders of ADSs represents some 818,000 underlying shareholders.

As at 31 December 2008, there were also 1,622 preference shareholders. Preference shareholders represented 0.44% and ordinary shareholders represented 99.56% of the total issued nominal share capital of the company as at that date.

Substantial shareholdings

As at the date of this report, the company had been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs) holds interests through its nominee, Guaranty Nominees Limited, in 5,184,252,501 ordinary shares (27.51% of the company s ordinary share capital excluding shares held in Treasury). Legal & General Group plc hold interests in 813,276,072 ordinary shares (4.32% of the company s ordinary share capital excluding shares held in treasury).

At the date of this report the company has also been notified of the following interests in preference shares: The National Farmers Union Mutual Insurance Society Limited holds interests in 945,000 8% cumulative first preference shares (13.07% of that class) and 987,000 9% cumulative second preference shares (18.03% of that class). M & G Investment Management Ltd. holds interests in 528,150 8% cumulative first preference shares (7.30% of that class) and 644,450 9% cumulative second preference shares (11.77% of that class). Aviva Investors Global Services Limited holds interests in 475,000 8% cumulative first preference shares (6.57% of that class). Lazard Asset Management Ltd. (U.K.) holds interests in 463,000 8% cumulative first preference shares (6.40% of that class). Duncan Lawrie Ltd. holds interests in 451,376 8% cumulative first preference shares (6.24% of that class). Co-operative Insurance Society Ltd. holds interests in 444,538 8% cumulative first preference shares (6.15% of that class) and 1,450,000 9% cumulative

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second preference shares (26.49% of that class). Ruffer LLP holds interests in 671,500 9% cumulative second preference shares (12.27% of that class).

The total preference shares in issue comprise only 0.44% of the company s total issued nominal share capital, the rest being ordinary shares.

Related-party transactions

Transactions between the group and its significant jointly controlled entities and associates are summarized in Financial statements Note 26 on page 138 and Financial statements Note 27 on page 139. In the ordinary course of its business, the group enters into transactions with various organizations with which certain of its directors or executive officers are associated. Except as described in this report, the group did not have material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2008 to 18 February 2009.

Dividends

BP has paid dividends on its ordinary shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be,
paid quarterly in March, June, September and December. Former Amoco Corporation and Atlantic Richfield Company shareholders will not be able to receive dividends, or proxy material, until they send in their Amoco Corporation or Atlantic Richfield Company common shares for exchange.

BP currently announces dividends for ordinary shares in US dollars and states an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the forward exchange rate in London over the five business days prior to the announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

The following table shows dividends announced and paid by the company per ADS for each of the past five years. In the case of dividends paid before 1 May 2004, the dividends shown are before the deemed credit allowed to shareholders resident in the US under the former income tax convention between the US and the UK and the associated withholding tax in respect thereof equal to the amount of such credit. (This deemed credit and associated withholding tax do not apply to dividends paid after 30 April 2004 to shareholders resident in the US.)

		March	June	September	December	Total
Dividends per American depositary share						
2004	UK pence	22.0	22.8	23.2	23.5	91.5
	US cents	40.5	40.5	42.6	42.6	166.2
	Canadian cents	53.7	54.8	56.7	52.2	217.4
2005	UK pence	27.1	26.7	30.7	30.4	114.9
	US cents	51.0	51.0	53.55	53.55	209.1

	Canadian cents	64.0	63.2	65.3	63.7	256.2
2006	UK pence	31.7	31.5	31.9	31.4	126.5
	US cents	56.25	56.25	58.95	58.95	230.40
	Canadian cents	64.5	64.1	67.4	66.5	262.5
2007	UK pence	31.5	30.9	31.7	31.8	125.9
	US cents	61.95	61.95	64.95	64.95	253.8
	Canadian cents	73.3	69.5	67.8	63.6	274.2
2008	**UK pence**	**40.9**	**41.0**	**42.2**	**52.2**	**176.3**
	US cents	**81.15**	**81.15**	**84.00**	**84.00**	**330.3**
	Canadian cents	**80.8**	**82.5**	**85.8**	**108.6**	**357.7**

A dividend reinvestment plan is in place whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the US or Canada or in any jurisdiction outside the UK where such an offer requires compliance by the company with any governmental or regulatory procedures or any similar formalities. A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on pages 8-10 and other matters that may affect the business of the group set out in Financial and operating performance on page 46 and in Liquidity and capital resources on page 54.

Legal proceedings

Save as disclosed in the following paragraphs, no member of the group is a party to, and no property of a member of the group is subject to, any pending legal proceedings that are significant to the group.

BP America Inc. (BP America) continues to be subject to oversight by an independent monitor, who has authority to investigate and report alleged violations of the US Commodity Exchange Act or US Commodity Futures Trading Commission (CFTC) regulations and to recommend corrective action. The appointment of the independent monitor was a condition of the deferred prosecution agreement (DPA) entered into with the US Department of Justice (DOJ) on 25 October 2007 relating to allegations that BP America manipulated the price of February 2004 TET physical propane and attempted to manipulate the price of TET propane in April 2003 and the companion consent order with the CFTC, entered the same day, resolving all criminal and civil enforcement matters pending at that time concerning propane trading by BP Products North America Inc. (BP Products). The DPA requires BP America s and certain of its affiliates continued co-operation with the US government investigations of the trades in question, as well as other trading matters that may arise. The DPA has a term of three years but can be extended by two additional one-year periods, and contemplates dismissal of all charges at the end of the term following the DOJ s determination that BP America has complied with the terms of the DPA. Investigations into BP s trading activities continue to be conducted from time to time.

Private complaints, including class actions, have also been filed against BP Products alleging propane price manipulation. The complaints contain allegations similar to those in the CFTC action as well as of violations of federal and state antitrust and unfair competition laws and state consumer protection statutes and unjust enrichment.

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complaints seek actual and punitive damages and injunctive relief. Settlement with one group of the class actions has received preliminary approval from the court and final approval is expected in 2009.

On 23 March 2005, an explosion and fire occurred in the isomerization unit of BP Products Texas City refinery as the unit was coming out of planned maintenance. Fifteen workers died in the incident and many others were injured. BP Products has resolved all civil claims arising from the incident, except for a small number of claims that remain on appeal following dismissal in the trial court.

In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued its final report on the incident. The report contained recommendations to the Texas City refinery and to the board of the company. In May 2007, BP responded to the CSB s recommendations. BP and the CSB continue to discuss BP s responses with the objective of the CSB agreeing to close-out its recommendations.

On 25 October 2007, the DOJ announced that it had entered into a criminal plea agreement with BP Products related to the March 2005 explosion and fire. Following BP Products guilty plea on 4 February 2008, pursuant to the plea agreement, to one felony violation of the risk management planning regulations promulgated under the US federal Clean Air Act, a series of appeals were taken by victims of the incident, who alleged that the plea agreement did not fully take into account the victims injuries. On 7 October 2008, after resolution of those appeals, BP Products returned to court to argue for acceptance of the guilty plea. At the plea hearing, the court advised that it would take the matter under review and decide whether to accept or reject the plea. If the court accepts the agreement, BP Products will pay a $50 million criminal fine and serve three years probation. Compliance with a 2005 OSHA settlement agreement and an agreed order entered into by BP Products with the Texas Commission on Environmental Quality (TCEQ) are conditions of probation. The TCEQ and the DOJ continue to investigate certain matters arising from the March 2005 explosion and fire.

On 29 November 2007, BP Exploration (Alaska) Inc. (BPXA) entered into a criminal plea agreement with the DOJ relating to leaks of crude oil in March and August 2006. BPXA s guilty plea, to a misdemeanour violation of the US Federal Water Pollution Control Act, included a term of three years probation. BPXA is eligible to petition the court for termination of the probation term if it meets certain benchmarks relating to replacement of the transit lines, upgrades to its leak detection system and improvements to its integrity management programme. BPXA continues to co-operate with a parallel State of Alaska civil investigation into the March and August 2006 spills, including three separate subpoenas issued to BPXA by the Alaska Department of Environmental Conservation. BPXA is also engaged in discussions with the DOJ, the EPA and the US Department of Transportation concerning a civil enforcement action relating to the 2006 Prudhoe Bay oil transit line incidents.

Shareholder derivative lawsuits alleging breach of fiduciary duty that were filed in US federal and state courts against the directors of the company and others, nominally the company and certain US subsidiaries, following the events relating to, inter alia, Prudhoe Bay, Texas City and the trading cases, have been settled (following court approval of the settlement terms) and the claims have been dismissed.

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results of operations, financial position or liquidity will not be material.

In January 2009, the TNK-BP shareholders resolved, or agreed a process for resolving, all outstanding claims between them, including those relating to Russian back taxes. The suit filed in Russia by a minority shareholder in TNK-BP Holding, alleging that an agreement by BP specialists to provide services to the TNK-BP group is invalid and demanding repayment of sums paid to BP for such services, has been withdrawn.

For certain information regarding environmental proceedings, see Environment US regional review on page 42.

The offer and listing

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on stock exchanges in France and Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent to the exchange electronically by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00 a.m. to 4.30 p.m. UK time but, in the event of a 20% movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US, the company s securities are traded in the form of ADSs, for which JPMorgan Chase Bank is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 13, New York, NY 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the New York Stock Exchange. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth for the periods indicated the highest

Additional information for shareholders

and lowest middle market quotations for BP s ordinary shares for the periods shown. These are derived from the Daily Official List of the LSE
and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange (NYSE) composite tape.

	Pence		Dollars	
	Ordinary shares		American depositary shares[a]	
	High	Low	High	Low
Year ended 31 December				
2004	561.00	407.75	62.10	46.65
2005	686.00	499.00	72.75	56.60
2006	723.00	558.50	76.85	63.52
2007	640.00	504.50	79.77	58.62
2008	657.25	370.00	77.69	37.57
Year ended 31 December				
2007: First quarter	574.50	504.50	67.27	58.62
Second quarter	606.50	542.50	72.49	64.42
Third quarter	617.00	516.00	75.25	61.10
Fourth quarter	640.00	548.00	79.77	67.24
2008: First quarter	**648.00**	**495.00**	**75.87**	**57.87**
Second quarter	**657.25**	**501.34**	**77.69**	**60.25**
Third quarter	**583.00**	**446.00**	**69.10**	**48.35**
Fourth quarter	**541.25**	**370.00**	**51.49**	**37.57**
2009: First quarter (to 18 February)	**566.50**	**461.50**	**49.83**	**39.45**
Month of				
September 2008	**536.00**	**446.00**	**58.13**	**48.35**
October 2008	**518.75**	**370.00**	**50.96**	**37.57**
November 2008	**540.00**	**450.25**	**51.49**	**39.45**
December 2008	**541.25**	**476.00**	**50.10**	**41.55**
January 2009	**566.50**	**470.50**	**49.83**	**39.45**
February 2009 (to 18 February)	**518.00**	**461.50**	**46.07**	**39.91**

[a]An ADS is equivalent to six 25 cent ordinary shares.
Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the NYSE is open, and the market prices for ADSs on the NYSE are closely related due to arbitrage among the various markets,

although differences may exist from time to time due to various factors, including UK stamp duty reserve tax.

On 18 February 2009, 864,042,084 ADSs (equivalent to 5,184,252,501 ordinary shares or some 27.51% of the total issued share capital, excluding treasury shares) were outstanding and were held by approximately 136,213 ADS holders. Of these, about 134,710 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 818,000 underlying holders.

On 18 February 2009, there were approximately 317,409 holders of record of ordinary shares. Of these holders, around 1,504 had registered addresses in the US and held a total of some 4,236,569 ordinary shares.

Since certain of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders of record in the US may not be representative of the number of beneficial holders or of their country of residence.

Additional information for shareholders

Memorandum and Articles of Association
The following summarizes certain provisions of the company s Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act and the company s Memorandum and Articles of Association. Information on where investors can obtain copies of the Memorandum and Articles of Association is described under the heading Documents on display on page 94.

On 24 April 2003, the shareholders of BP voted at the AGM to adopt new Articles of Association to consolidate amendments that had been necessary to implement legislative changes since the previous Articles of Association were adopted in 1983.

At the AGM held on 15 April 2004, shareholders approved an amendment to the Articles of Association such that, at each AGM held after 31 December 2004, all directors shall retire from office and may offer themselves for re-election.

At the AGM held on 17 April 2008, shareholders voted to adopt new Articles of Association, largely to take account of changes in UK company law brought about by the Companies Act 2006. Further amendments to the Articles of Association are likely to be required at our AGM in 2010, to reflect the full implementation of the Companies Act 2006.

Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with registered number 102498. Clause 4 of BP s Memorandum of Association provides that its objects include the acquisition of petroleum-bearing lands; the carrying on of refining and dealing businesses in the petroleum, manufacturing, metallurgical or chemicals businesses; the purchase and operation of ships and all other vehicles and other conveyances; and the carrying on of any other businesses calculated to benefit BP. The memorandum grants BP a range of corporate capabilities to effect these objects.

Directors

The business and affairs of BP shall be managed by the directors.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which he has a material interest other than by virtue of his interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company.

- Any proposal in which he is interested concerning the underwriting of company securities or debentures.

- Any proposal concerning any other company in which he is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that he and persons connected with him are not the holder or holders of 1% or more of the voting interest in the shares of such company.

- Proposals concerning the modification of certain retirement benefits schemes under which he may benefit and that have been approved by either the UK Board of Inland Revenue or by the shareholders.

- Any proposal concerning the purchase or maintenance of any insurance policy under which he may benefit.

The UK Companies Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of his interest at a meeting of the directors of the company. The definition of interest includes the interests of spouses, children, companies and trusts. The UK Companies Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company s interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company s Articles of Association so permit. BP s Articles of

Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be effected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director s qualification.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under IFRS and the UK Companies Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of 12 years from the date of declaration of such dividend shall be forfeited and reverts to BP.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of paying dividends in US dollars.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared), the Articles of Association provide that the directors may set aside:

A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares.

A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Additional information for shareholders

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested. Shareholders do not have cumulative voting rights.

Holders of record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders meeting.

Record holders of BP ADSs are also entitled to attend, speak and vote at any shareholders meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank, of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of BP ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are three types: ordinary, special or extraordinary. An annual general meeting must be held once in every year and all other general meetings will be called extraordinary general meetings.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. Special and extraordinary resolutions require the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any AGM requires 21 days notice. The notice period for an extraordinary general meeting is 14 days. With the implementation of the EU Shareholder Rights Directive into UK law expected later this year, reliance on this notice period of 14 days will require annual shareholder approval, failing which, a 21-day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (i) the capital paid up on such shares plus, (ii) accrued and unpaid dividends and (iii) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of an extraordinary resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one-third or more of the shares of that class.

Shareholders meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK in order to be entitled to receive notice of shareholders meetings. In certain circumstances, BP may give notices to shareholders by advertisement in UK newspapers. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices is described above under the heading Voting Rights.

Under the Articles of Association, the AGM of shareholders will be held within the six-month period from the first day of BP s accounting period. All general meetings shall be held at a time and place determined by the directors within the UK. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

Limitations on voting and shareholding

There are no limitations imposed by English law or the company s Memorandum or Articles of Association on the right of non-residents or foreign persons to hold or vote the company s ordinary shares or ADSs, other than limitations that would generally apply to all of the shareholders.

Disclosure of interests in shares

The UK Companies Act permits a public company, on written notice, to require any person whom the company believes to be or, at any time during the previous three years prior to the issue of the notice, to have been interested in its voting shares, to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term interest is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

Exchange controls

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company s operations.

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company.

Taxation

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, to members of special classes of holders subject to special rules and holders that, directly or indirectly, hold 10% or more of the company s voting stock.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention

Additional information for shareholders

between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section is further based in part on the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention), and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, the UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder in taxable years beginning before 1 January 2011 that constitute qualified dividend income will be taxable to the holder at a maximum tax rate of 15%, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the shares or ADSs will generally be qualified dividend income.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. A US holder will include in gross income for US federal income tax purposes the amount of the dividend actually received from the company and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend, and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Dividends will be income from sources outside the US, and generally will be passive category income or, in the case of certain US holders, general category income, each of which is treated separately for purposes of computing the allowable foreign tax credit.

The amount of the dividend distribution on the ordinary shares or ADSs that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is in fact converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the 15% tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company s earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains US federal income taxation.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the US resident or ordinarily resident in the UK, (ii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iii) a citizen of the US or a corporation that carries on a trade or profession or vocation in the UK through a branch or agency or, in respect of corporations for accounting periods beginning on or after 1 January 2003, through a permanent establishment, and that have used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

US federal income taxation

A US holder that sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized and the holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Capital gain of a non-corporate US holder that is recognized in taxable years beginning before 1 January 2011 is generally taxed at a maximum rate of 15% if the holder s holding period for such ordinary shares or ADSs exceeds one year. The gain or loss will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company, or PFIC, for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-mark basis with respect to ordinary shares or ADSs, gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead a US holder would be treated as if he or she had realized such gain and certain excess distributions ratably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply.

Additional information for shareholders

Additional tax considerations

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject both to inheritance tax and to US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer.

An ADR holder electing to receive ADSs instead of a cash dividend will be responsible for the stamp duty reserve tax due on issue of shares to the Depositary s nominee and calculated at the rate of 1.5% on the issue price of the shares. It is understood that HM Revenue & Customs practice is to calculate the issue price by reference to the total cash receipt to which a US holder would have been entitled had the election to receive ADSs instead of a cash dividend not been made. ADR holders electing to receive ADSs instead of the cash dividend authorize the Depositary to sell sufficient shares to cover this liability.

Documents on display

BP s Annual Report and Accounts is also available online at *www.bp.com/annualreport*. Shareholders may obtain a hard copy of BP s complete audited financial statements, free of charge, by contacting BP Distribution Services at +44 (0)870 241 3269 or through an email request addressed to *bpdistributionservices@bp.com*, or BP s US Shareholder Services office in Warrenville, Illinois at +1 800 638 5672 or through an email request addressed to *shareholderus@bp.com*.

The company is subject to the information requirements of the US Securities Exchange Act of 1934 (the Exchange Act) applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report on Form 20-F and other related documents with the SEC. It is possible to read and copy documents that have been filed with the SEC at the SEC s public reference room located at 100 F Street NE, Washington, DC 20549, US. You may also call the SEC at +1 800-SEC-0330 or log on to *www.sec.gov*. In addition, BP s SEC filings are available to the public at the SEC s website *www.sec.gov*. BP discloses on its website at *www.bp.com/NYSEcorporategovernancerules*, and in its Annual Report on Form 20-F (Item 16G) significant ways (if any) in which its corporate governance practices differ

from those mandated for US companies under NYSE listing standards.
Material modifications to the rights of security holders and use of proceeds
During 2008, the Depositary and transfer agent for BP s ADSs changed its contact address to PO Box 64504, St. Paul, MN 55164-0504.
Controls and procedures
Evaluation of disclosure controls and procedures
The company maintains disclosure controls and procedures as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company s group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, mis-statements due to error or fraud may occur and not be detected. The company s disclosure controls and procedures have been designed to meet, and management believe that they meet, reasonable assurance standards.

The company s management, with the participation of the company s group chief executive and chief financial officer, has evaluated the effectiveness of the company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company s disclosure controls and procedures were effective at a reasonable assurance level.
Changes in internal controls over financial reporting
There were no changes in the Group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect, our internal controls over financial reporting.

During 2008, as part of an ongoing process, improvements were made in the design and operation of the Group s internal control over financial reporting including those relating to the valuation of inventory

Additional information for shareholders

and the elimination of unrealised profit arising on transfers of inventory between business segments. These improvements included clarifying roles and accountabilities, implementing additional preventative and detective controls and providing additional staff training.

Management s report on internal control over financial reporting

Management of BP is responsible for establishing and maintaining adequate internal control over financial reporting. BP s internal control over financial reporting is a process designed under the supervision of the principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of BP s financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2008 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull). Based on this assessment, management has determined that BP s internal control over financial reporting as of 31 December 2008 was effective.

The company s internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of BP; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of BP s assets that could have a material effect on our financial statements.

BP s internal control over financial reporting as of 31 December 2008 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report appearing on page 100.

Audit committee financial expert

The board determined that Douglas Flint is the audit committee member with recent and relevant financial experience as defined by the Combined Code guidance.

The board also determined that Douglas Flint meets the independence criteria provisions of Rule 10A-3 of the Exchange Act and that Mr Flint may be regarded as an audit committee financial expert as defined in Item 16A of Form 20-F. Mr Flint is group finance director of HSBC Holdings plc and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, general auditor, group chief accounting officer and deputy chief financial officer (previously titled group controller) as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no amendments to, or waivers from, the code of ethics relating to any of those officers. The code of ethics has been filed as an exhibit to our Annual Report on Form 20-F.

In June 2005, BP published a code of conduct, which is applicable to all employees.

Principal accountants fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically
defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint ventures (excluding valuation or involvement in prospective financial information); income tax and indirect tax compliance and advisory services; and employee tax services (excluding tax services that could impair independence); provision of, or access to, Ernst & Young publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; and assistance with understanding non-financial regulatory requirements. Additionally, any proposed service not included in the pre-approved services, must be approved in advance prior to commencement of the engagement. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting.

The audit committee evaluates the performance of the auditors each year. The audit fees payable to Ernst & Young are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditors. External regulation and BP policy requires the auditors to rotate their lead audit partner every five years.

(See Financial statements Notes 18 and 48 on pages 132 and 178 for details of audit fees.)

Corporate governance practices

In the US, BP ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between BP s corporate governance practices and those required by NYSE listing standards for US companies are listed as follows:

Independence

BP has adopted a robust set of board governance principles, which reflect the UK s prevailing principles-based approach to corporate governance. As such, the way in which BP makes determinations of directors independence differs from the NYSE rules. Rule 303A.02 under NYSE s Listed Company Manual sets out five bright line tests for director independence. In addition to these five tests, the NYSE also requires that the board of directors affirmatively determines that the director has no material relationship with the company (either directly or as a partner, shareholder or officer of an organization that has a relationship with the company) .

BP s board governance principles require that all non-executive directors be determined by the board to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement .

The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the NYSE s five bright line tests.

Additional information for shareholders

Committees

BP has a number of board committees which are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman s (rather than executive) committee, nomination (rather than nominating/corporate governance) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see The Board Committees on page 67). BP has not, therefore, adopted separate charters for each committee.

One of the NYSE s additional requirements for the audit committee states that at least one member of the audit committee is to have accounting or related financial management expertise . For 2008, the board determined that Douglas Flint possessed such expertise and also possesses the financial and audit committee experiences set forth in both the Combined Code and SEC rules (See Audit Committee Financial Expert on page 95).

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. BP complies with UK requirements which are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE s detailed definition of what are considered material revisions .

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. BP has adopted a code of conduct, which applies to all employees, and has board governance principles which address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Additional information for shareholders

Purchases of equity securities by the issuer and affiliated purchasers
The following table provides details of ordinary shares repurchased.

	Total number of shares purchased[a b]	$ Average price paid per share	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programme[c]
2008				
January	**41,187,000**	**11.26**	**41,187,000**	
February	**24,314,706**	**10.90**	**24,314,706**	
March	**25,494,193**	**10.60**	**25,494,193**	
April	**28,537,196**	**11.02**	**28,537,196**	
May	**27,570,000**	**12.34**	**27,570,000**	
June	**29,793,000**	**11.58**	**29,793,000**	
July	**32,285,000**	**10.67**	**32,285,000**	
August	**33,006,764**	**9.86**	**33,006,764**	
September	**27,569,329**	**8.92**	**27,569,329**	
October				
November				
December				
2009				
January				
February (to 18 February)				

[a]All share purchases were open market transactions.

[b]All shares were repurchased for cancellation.

[c]At the AGM on 17 April 2008, authorization was given to repurchase up to 1.9 billion ordinary shares in the period to the next AGM in 2009 or 16 July 2009, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM.
The following table provides details of share purchases made by ESOP trusts.

Total number of	$ Average price	Total number of shares purchased as part of publicly announced	Maximum number of shares that may yet be purchased under

	shares purchased	paid per share	programmes[a]	the programme[a]
2008				
January				
February				
March	**30,000,000**	**11.41**		
April	**680**	**11.53**		
May				
June				
July	**63**	**11.08**		
August	**1,500,000**	**9.49**		
September	**81,694**	**8.73**		
October	**1,000,772**	**7.39**		
November	**166**	**10.09**		
December	**59,049**	**8.09**		
2009				
January				
February (to 18 February)	**126**	**7.65**		

[a]No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOP trusts to satisfy future requirements of employee share schemes.

Additional information for shareholders

Called-up share capital
Details of the allotted, called up and fully paid share capital at 31 December 2008 are set out in Financial statements Note 39 on page 163.

At the AGM on 17 April 2008, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $1,586 million. Authority was also given to the directors to allot shares for cash and to dispose of treasury shares, other than by way of rights issue, up to a maximum of $238 million, without having to offer such shares to existing shareholders. These authorities are given for the period until the next AGM in 2009 or 16 July 2009, whichever is the earlier. These authorities are renewed annually at the AGM.

Annual general meeting
The 2009 AGM will be held on Thursday 16 April 2009 at 11.30 a.m. at ExCeL London, One Western Gateway, Royal Victoria Dock, London E16 1XL. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in *Notice of BP Annual General Meeting 2009*.

By order of the board
David J Jackson
Secretary
24 February 2009

Exhibits

The following documents are filed as part of this annual report:

Exhibit 4.1	The BP Executive Directors Incentive Plan**
Exhibit 4.2	Medium Term Performance Plan
Exhibit 4.3	Deferred Annual Bonus Plan
Exhibit 4.4	Performance Share Plan
Exhibit 7.	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8.	Subsidiaries
Exhibit 11.	Code of Ethics***
Exhibit 12.	Rule 13a 14(a) Certifications
Exhibit 13.	Rule 13a 14(b) Certifications#

*Incorporated by reference to the company s Report on Form 6-K filed on 22 May 2008.
**Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.

***Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2003.

#Furnished only.

Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

Administration
If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the dividend reinvestment plan or the ADS direct access plan, or to change the way you receive

your company documents (such as the Annual Report and Accounts, Annual Review and Notice of Meeting) please contact the BP Registrar or ADS Depositary.

UK Registrar s Office
The BP Registrar, Equiniti
Aspect House, Spencer Road, Lancing, West Sussex BN99 6DA
Freephone in UK 0800 701107; Tel +44 (0)121 415 7005
Textphone 0871 384 2255; Fax +44 (0)871 384 2100
Please note that any numbers quoted with the prefix 0871 will be charged at 8p per minute from a BT landline. Other network providers costs may vary.

US ADS Depositary
JPMorgan Chase Bank, N.A.
PO Box 64504, St. Paul, MN 55164-0504
Toll-free in US and Canada +1 877 638 5672; Tel +1 651 306 4383
For the hearing impaired +1 651 453 2133

Financial statements

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2008 and 2007, and the related group statements of income, cash flows, and recognized income and expense, for each of the three years in the period ended 31 December 2008. These financial statements are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the group financial position of BP p.l.c. at 31 December 2008 and 2007, and the group results of operations and cash flows for each of the three years in the period ended 31 December 2008, in accordance with International Financial Reporting Standards as adopted by the European Union and International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of BP p.l.c. s internal control over financial reporting as of 31 December 2008, based on criteria established in the Internal Control Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria) and our report dated 24 February 2009 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP
London, England
24 February 2009

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of BP p.l.c.

We have audited BP p.l.c. s internal control over financial reporting as of 31 December 2008, based on criteria established in Internal Control-Revised Guidance for Directors on the Combined Code (Turnbull) as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull criteria). BP p.l.c. s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s report on internal control over financial reporting on page 95. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2008, based on the Turnbull criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the group balance sheets of BP p.l.c. as of 31 December 2008 and 2007, and the related group statements of income, cash flows and recognized income and expense, for each of the three years in the period ended 31 December 2008, and our report dated 24 February 2009 expressed an unqualified opinion thereon.

/s/ERNST & YOUNG LLP

Ernst & Young LLP
London, England
24 February 2009

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Consolidated financial statements of the BP group

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 24 February 2009 with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report (Form 20-F) for the year ended 31 December 2008 in the following registration statements:

Registration Statement on Form F-3 (File No. 333-155798) of BP p.l.c.;

Registration Statement on Form F-3 (File No. 333-110203) of BP Canada Finance Company, BP Capital Markets p.l.c., BP Capital Markets America Inc, and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 333-149778, 333-79399, 333-67206, 333-102583, 333-103923, 333-103924, 333-119934, 333-123482, 333-123483, 333-132619, 333-131584, 333-131583, 333-146868, 333-146870 and 333-146873) of BP p.l.c.

/s/ERNST & YOUNG LLP

Ernst & Young LLP
London, England
4 March 2009

Consolidated financial statements of the BP group

Group income statement

				$ million
For the year ended 31 December	Note	**2008**	2007	2006
Sales and other operating revenues		**361,143**	284,365	265,906
Earnings from jointly controlled entities after interest and tax		**3,023**	3,135	3,553
Earnings from associates after interest and tax		**798**	697	442
Interest and other revenues	7	**736**	754	701
Total revenues	6	**365,700**	288,951	270,602
Gains on sale of businesses and fixed assets	8	**1,353**	2,487	3,714
Total revenues and other income		**367,053**	291,438	274,316
Purchases		**266,982**	200,766	187,183
Production and manufacturing expenses		**29,183**	25,915	23,293
Production and similar taxes	9	**6,526**	4,013	3,621
Depreciation, depletion and amortization	10	**10,985**	10,579	9,128
Impairment and losses on sale of businesses and fixed assets	11	**1,733**	1,679	549
Exploration expense	17	**882**	756	1,045
Distribution and administration expenses	13	**15,412**	15,371	14,447
Fair value (gain) loss on embedded derivatives	34	**111**	7	(608)
Profit before interest and taxation from continuing operations		**35,239**	32,352	35,658
Finance costs	19	**1,547**	1,393	986
Net finance income relating to pensions and other post-retirement benefits	38	**(591)**	(652)	(470)
Profit before taxation from continuing operations		**34,283**	31,611	35,142
Taxation	20	**12,617**	10,442	12,516
Profit from continuing operations		**21,666**	21,169	22,626
Loss from Innovene operations	4			(25)
Profit for the year		**21,666**	21,169	22,601
Attributable to				
BP shareholders		**21,157**	20,845	22,315
Minority interest		**509**	324	286
		21,666	21,169	22,601

Earnings per share cents				
Profit for the year attributable to BP shareholders				
Basic	22	**112.59**	108.76	111.41
Diluted	22	**111.56**	107.84	110.56
Profit from continuing operations attributable to BP shareholders				
Basic		**112.59**	108.76	111.54
Diluted		**111.56**	107.84	110.68

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Consolidated financial statements of the BP group

Group balance sheet

At 31 December			$ million
	Note	**2008**	2007
Non-current assets			
Property, plant and equipment	23	**103,200**	97,989
Goodwill	24	**9,878**	11,006
Intangible assets	25	**10,260**	6,652
Investments in jointly controlled entities	26	**23,826**	18,113
Investments in associates	27	**4,000**	4,579
Other investments	29	**855**	1,830
Fixed assets		**152,019**	140,169
Loans		**995**	999
Other receivables	31	**710**	968
Derivative financial instruments	34	**5,054**	3,741
Prepayments		**1,338**	1,083
Defined benefit pension plan surpluses	38	**1,738**	8,914
		161,854	155,874
Current assets			
Loans		**168**	165
Inventories	30	**16,821**	26,554
Trade and other receivables	31	**29,261**	38,020
Derivative financial instruments	34	**8,510**	6,321
Prepayments		**3,050**	3,589
Current tax receivable		**377**	705
Cash and cash equivalents	32	**8,197**	3,562
		66,384	78,916
Assets classified as held for sale	4		1,286
		66,384	80,202
Total assets		**228,238**	236,076
Current liabilities			
Trade and other payables	33	**33,644**	43,152
Derivative financial instruments	34	**8,977**	6,405
Accruals		**6,743**	6,640
Finance debt	35	**15,740**	15,394
Current tax payable		**3,144**	3,282
Provisions	37	**1,545**	2,195

		69,793	77,068
Liabilities directly associated with the assets classified as held for sale	4		163
		69,793	77,231
Non-current liabilities			
Other payables	33	**3,080**	1,251
Derivative financial instruments	34	**6,271**	5,002
Accruals		**784**	959
Finance debt	35	**17,464**	15,651
Deferred tax liabilities	20	**16,198**	19,215
Provisions	37	**12,108**	12,900
Defined benefit pension plan and other post-retirement benefit plan deficits	38	**10,431**	9,215
		66,336	64,193
Total liabilities		**136,129**	141,424
Net assets		**92,109**	94,652
Equity			
Share capital	39	**5,176**	5,237
Reserves		**86,127**	88,453
BP shareholders equity	40	**91,303**	93,690
Minority interest	40	**806**	962
Total equity	40	**92,109**	94,652

P D Sutherland Chairman
Dr A B Hayward Group Chief Executive

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Consolidated financial statements of the BP group

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2008**	2007	2006
Operating activities				
Profit before taxation		**34,283**	31,611	35,142
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	17	**385**	347	624
Depreciation, depletion and amortization	10	**10,985**	10,579	9,128
Impairment and (gain) loss on sale of businesses and fixed assets	8,11	**380**	(808)	(3,165)
Earnings from jointly controlled entities and associates		**(3,821)**	(3,832)	(3,995)
Dividends received from jointly controlled entities and associates		**3,728**	2,473	4,495
Interest receivable		**(407)**	(489)	(473)
Interest received		**385**	500	500
Finance costs	19	**1,547**	1,393	986
Interest paid		**(1,291)**	(1,363)	(1,242)
Net finance income relating to pensions and other post-retirement benefits	38	**(591)**	(652)	(470)
Share-based payments		**459**	420	416
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(173)**	(404)	(261)
Net charge for provisions, less payments		**(298)**	(92)	(160)
(Increase) decrease in inventories		**9,010**	(7,255)	995
(Increase) decrease in other current and non-current assets		**2,439**	5,210	3,596
Increase (decrease) in other current and non-current liabilities		**(6,101)**	(3,857)	(4,211)
Income taxes paid		**(12,824)**	(9,072)	(13,733)
Net cash provided by operating activities		**38,095**	24,709	28,172
Investing activities				
Capital expenditure		**(22,658)**	(17,830)	(15,125)
Acquisitions, net of cash acquired		**(395)**	(1,225)	(229)
Investment in jointly controlled entities		**(1,009)**	(428)	(37)
Investment in associates		**(81)**	(187)	(570)
Proceeds from disposal of fixed assets	5	**918**	1,749	5,963
Proceeds from disposal of businesses, net of cash disposed	5	**11**	2,518	291
Proceeds from loan repayments		**647**	192	189
Other		**(200)**	374	

Net cash used in investing activities		**(22,767)**	(14,837)	(9,518)
Financing activities				
Net repurchase of shares		**(2,567)**	(7,113)	(15,151)
Proceeds from long-term financing		**7,961**	8,109	3,831
Repayments of long-term financing		**(3,821)**	(3,192)	(3,655)
Net increase (decrease) in short-term debt		**(1,315)**	1,494	3,873
Dividends paid				
BP shareholders	21	**(10,342)**	(8,106)	(7,686)
Minority interest		**(425)**	(227)	(283)
Net cash used in financing activities		**(10,509)**	(9,035)	(19,071)
Currency translation differences relating to cash and cash equivalents		**(184)**	135	47
Increase (decrease) in cash and cash equivalents		**4,635**	972	(370)
Cash and cash equivalents at beginning of year		**3,562**	2,590	2,960
Cash and cash equivalents at end of year		**8,197**	3,562	2,590

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Consolidated financial statements of the BP group

Group statement of recognized income and expense

For the year ended 31 December			$ million
	2008	2007	2006
Currency translation differences	**(4,362)**	1,887	2,025
Exchange gain on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		(147)	
Actuarial (loss) gain relating to pensions and other post-retirement benefits	**(8,430)**	1,717	2,615
Available-for-sale investments marked to market	**(994)**	200	561
Available-for-sale investments recycled to the income statement	**526**	(91)	(695)
Cash flow hedges marked to market	**(1,173)**	155	413
Cash flow hedges recycled to the income statement	**45**	(74)	(93)
Cash flow hedges recycled to the balance sheet	**(38)**	(40)	(6)
Tax on currency translation differences	**100**	139	(201)
Tax on actuarial (loss) gain relating to pensions and other post-retirement benefits	**2,602**	(427)	(820)
Tax on available-for-sale investments	**50**	(14)	108
Tax on cash flow hedges	**194**	26	(47)
Tax on share-based payments	**(190)**	213	26
Net (expense) income recognized directly in equity	**(11,670)**	3,544	3,886
Profit for the year	**21,666**	21,169	22,601
Total recognized income and expense for the year	**9,996**	24,713	26,487
Attributable to			
BP shareholders	**9,562**	24,365	26,152
Minority interest	**434**	348	335
	9,996	24,713	26,487

Notes on financial statements

1. Significant accounting policies

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of the BP group for the year ended 31 December 2008 were authorized for issue by the board of directors on 24 February 2009 and the balance sheet was signed on the board s behalf by P D Sutherland and Dr A B Hayward. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and IFRS as adopted by the European Union (EU). IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB, however, the differences have no impact on the group s consolidated financial statements for the years presented. The significant accounting policies of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared in accordance with IFRS and International Financial Reporting Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2008, or issued and early adopted.

Standards and interpretations adopted in the year had no significant impact on the financial statements.

Subsequent to releasing our preliminary announcement of the fourth quarter 2008 results on 3 February 2009, an adjustment has been made to correct for a $560 million overstatement of the deferred tax liability in the balance sheet as at 31 December 2008 with a corresponding adjustment to the foreign currency translation reserve in equity. There was no impact on profit for the year.

The accounting policies that follow have been consistently applied to all years presented.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

For further information regarding the key judgements and estimates made by management in applying the group s accounting policies, refer to Critical accounting policies on pages 57 to 59, which forms part of these financial statements.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to 31 December each year. Control comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. All intercompany balances and transactions, including unrealized profits arising from intragroup transactions, have been eliminated in full. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Minority interests represent the portion of profit or loss and net assets in subsidiaries that is not held by the group.

Interests in joint ventures

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the group s share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controlled entities are also included in the investment on the group balance sheet. The group income statement reflects the group s share of the results after tax of the jointly controlled entity. The group statement of recognized income and expense reflects the group s share of any income and expense recognized by the jointly controlled entity outside profit and loss.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its jointly controlled entities are eliminated to the extent of the group s interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs to sell and value in use. Where the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting on the date from which it no longer has joint control or significant influence over the joint venture, or when the interest becomes held for sale.

Certain of the group s activities, particularly in the Exploration and Production segment, are conducted through joint ventures where the venturers have a direct ownership interest in and jointly control the assets of the venture. The income, expenses, assets and liabilities of these jointly controlled assets are included in the consolidated financial statements in proportion to the group s interest.

Interests in associates

An associate is an entity over which the group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but that is not a subsidiary or a jointly controlled entity.

The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described above for jointly controlled entities.

Notes on financial statements

1. Significant accounting policies continued

Foreign currency translation

Functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash.

In individual companies, transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement. Non-monetary assets and liabilities that are measured at historical cost and denominated in a foreign currency are translated into the functional currency using the rates of exchange as at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated into the functional currency using the rate of exchange at the date the fair value was determined.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, jointly controlled entities and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, jointly controlled entities and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of recognized income and expense. Exchange gains and losses arising on long-term intragroup foreign currency borrowings used to finance the group s non-US dollar investments are also taken to equity. On disposal of a non-US dollar functional currency subsidiary, jointly controlled entity or associate, the deferred cumulative amount recognized in equity relating to that particular non-US dollar operation is recognized in the income statement.

Business combinations and goodwill

Business combinations are accounted for using the purchase method of accounting. The cost of an acquisition is measured as the cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange, plus costs directly attributable to the acquisition. The acquired identifiable assets, liabilities and contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired (i.e. discount on acquisition) is credited to the income statement in the period of acquisition. Where the group does not acquire 100% ownership of the acquired company, the interest of minority shareholders is stated at the minority s proportion of the fair values of the assets and liabilities recognized. Subsequently, any losses applicable to the minority shareholders in excess of the minority interest on the group balance sheet are allocated against the interests of the parent.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units expected to benefit from the combination s synergies. For this purpose, cash-generating units are set at one level below a business segment.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses. Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate that the carrying value may be impaired.

Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice.

Goodwill may also arise upon investments in jointly controlled entities and associates, being the surplus of the cost of investment over the group s share of the net fair value of the identifiable assets. Such goodwill is recorded within investments in jointly controlled entities and associates, and any impairment of the goodwill is included within the earnings from jointly controlled entities and associates.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification.

Property, plant and equipment and intangible assets once classified as held for sale are not depreciated.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights and its fair value can be measured reliably.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, which can range from three to 15 years. Computer software costs have a useful life of three to five years.

The expected useful lives of assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

Notes on financial statements

1. Significant accounting policies continued

Oil and natural gas exploration and development expenditure

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Exploration expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production as described below in the accounting policy for Property, plant and equipment.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes are expensed as incurred. All other maintenance costs are expensed as incurred.

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, field development and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the amortization of field development costs takes into account expenditures incurred to date, together with approved future development expenditure required to develop reserves.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life.

The useful lives of the group s other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

The carrying value of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period the item is derecognized.

Notes on financial statements

1. Significant accounting policies continued

Impairment of intangible assets and property, plant and equipment

The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, for example, low prices or margins for an extended period or for oil and gas assets significant downward revisions of estimated volumes or increases in estimated future development expenditure. If any such indication of impairment exists, the group makes an estimate of its recoverable amount. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. An asset group s recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset s recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset s revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets

Financial assets are classified as loans and receivables; available-for-sale financial assets; financial assets at fair value through profit or loss; or as derivatives designated as hedging instruments in an effective hedge, as appropriate. Financial assets include cash and cash equivalents, trade receivables, other receivables, loans, other investments, and derivative financial instruments. The group determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

The subsequent measurement of financial assets depends on their classification, as follows:

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes trade and other receivables.

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized as a separate component of equity until the investment is derecognized or impaired.

The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. Where fair value cannot be reliably measured, assets are carried at cost.

Financial assets at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These assets are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for Derivative financial instruments and hedging activities.

Impairment of financial assets

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Loans and receivables

If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the financial asset s original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in profit or loss.

Available-for-sale financial assets

If an available-for-sale financial asset is impaired, the cumulative gain or loss previously recognized in equity is transferred to the income statement.

If there is objective evidence that an impairment loss on an unquoted equity instrument that is carried at cost has been incurred, the amount of the loss is measured as the difference between the asset s carrying amount and the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset.

Inventories

Inventories, other than inventory held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in net realizable value are recognized in the income statement.

Supplies are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

Notes on financial statements

1. Significant accounting policies continued

Financial liabilities

Financial liabilities are classified as financial liabilities at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; or as financial liabilities measured at amortized cost, as appropriate. Financial liabilities include trade and other payables, accruals, finance debt and derivative financial instruments. The group determines the classification of its financial liabilities at initial recognition. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category. These liabilities are carried on the balance sheet at fair value with gains or losses recognized in the income statement.

Derivatives designated as hedging instruments in an effective hedge

Such derivatives are carried on the balance sheet at fair value, the treatment of gains and losses arising from revaluation are described below in the accounting policy for Derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other revenues and finance costs.

This category of financial liabilities includes trade and other payables and finance debt.

Leases

Finance leases, which transfer to the group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

For both finance and operating leases, contingent rents are recognized in the income statement in the period in which they are incurred.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. Such derivative financial instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item that can be settled net in cash or another financial instrument, or by exchanging financial instruments, as if the contracts were financial instruments, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group s expected purchase, sale or usage requirements, are accounted for as financial instruments.

Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

For the purpose of hedge accounting, hedges are classified as:

Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.

Cash flow hedges when hedging exposure to variability in cash flows that is either attributable to a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedges of a net investment in a foreign operation.

At the inception of a hedge relationship the group formally designates and documents the hedge relationship for which the group wishes to claim hedge accounting, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item s fair value or cash flows attributable to the hedged item. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows.

Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss.

The group applies fair value hedge accounting for hedging fixed interest rate risk on borrowings. The gain or loss relating to the effective portion of the interest rate swap is recognized in the income statement within finance costs, offsetting the amortization of the interest on the underlying borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the adjustment to the carrying amount of a hedged item for which the effective interest rate method is used is amortized to profit or loss over the period to maturity.

Cash flow hedges

For cash flow hedges, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the hedged transaction affects profit or loss. The gain or loss relating to the effective portion of interest rate swaps hedging variable rate borrowings is recognized in the income statement within finance costs.

Where the hedged item is the cost of a non-financial asset or liability, such as a forecast transaction for the purchase of property, plant and equipment, the amounts taken to equity are transferred to the initial carrying amount of the non-financial asset or liability.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized in equity remain in equity until the forecast transaction occurs and are transferred to the income statement or to the initial carrying amount of a non-financial asset or liability as above. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are transferred to profit or loss.

Notes on financial statements

1. Significant accounting policies continued

Hedges of a net investment in a foreign operation

For hedges of a net investment in a foreign operation, the effective portion of the gain or loss on the hedging instrument is recognized directly in equity, while the ineffective portion is recognized in profit or loss. Amounts taken to equity are transferred to the income statement when the foreign operation is sold or partially disposed.

Embedded derivatives

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. Embedded derivatives are measured at fair value at each balance sheet date. Any gains or losses arising from changes in fair value are taken directly to profit or loss.

Provisions and contingencies

Provisions are recognized when the group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs.

A contingent liability is disclosed where the existence of an obligation will only be confirmed by future events or where the amount of the obligation cannot be measured reliably. Contingent assets are not recognized, but are disclosed where an inflow of economic benefits is probable.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility, such as oil and natural gas production or transportation facilities, this will be on construction or installation. An obligation for decommissioning may also crystallize during the period of operation of a facility through a change in legislation or through a decision to terminate operations. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of property, plant and equipment of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the asset.

Other than the unwinding discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding item of property, plant and equipment.

Environmental expenditures and liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the period end are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policy for pensions and other post-retirement benefits is described below.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the relevant employees become fully entitled to the award. Fair value is determined by using an appropriate valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions).

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management s best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

Where the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

Where an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately. Any compensation paid up to the fair value of the award at the cancellation or settlement date is deducted from equity, with any excess over fair value being treated as an expense in the income statement.

Notes on financial statements

1. Significant accounting policies continued

Cash-settled transactions

The cost of cash-settled transactions is measured at fair value and recognized as an expense over the vesting period, with a corresponding liability recognized on the balance sheet.

Pensions and other post-retirement benefits

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of the defined benefit obligation). Past service costs are recognized immediately when the company becomes committed to a change in pension plan design. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss is recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on scheme assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full in the group statement of recognized income and expense in the period in which they occur.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price.

Contributions to defined contribution schemes are recognized in the income statement in the period in which they become payable.

Corporate taxes

Income tax expense represents the sum of the tax currently payable and deferred tax. Interest and penalties relating to tax are also included in income tax expense.

The tax currently payable is based on the taxable profits for the period. Taxable profit differs from net profit as reported in the income statement because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The group s liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on all temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for all taxable temporary differences:

Except where the deferred tax liability arises on goodwill that is not tax deductible or the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

In respect of taxable temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, except where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax assets and unused tax losses can be utilized:

Except where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss.

In respect of deductible temporary differences associated with investments in subsidiaries, jointly controlled entities and associates, deferred tax assets are only recognized to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Tax relating to items recognized directly in equity is recognized in equity and not in the income statement.

Customs duties and sales taxes

Revenues, expenses and assets are recognized net of the amount of customs duties or sales tax except:

Where the customs duty or sales tax incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset or as part of the expense item as applicable.

Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the balance sheet.

Own equity instruments

The group s holdings in its own equity instruments, including ordinary shares held by Employee Share Ownership Plans (ESOPs), are classified as treasury shares , or own shares for the ESOPs, and are shown as deductions from shareholders equity at cost. Consideration received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares.

Notes on financial statements

1. Significant accounting policies continued

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Revenues associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and chemicals products and all other items are recognized when the title passes to the customer. Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded. Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint venture partners are recognized on the basis of the group s working interest in those properties (the entitlement method). Differences between the production sold and the group s share of production are not significant.

Interest income is recognized as the interest accrues (using the effective interest rate that is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument) to the net carrying amount of the financial asset.

Dividend income from investments is recognized when the shareholders right to receive the payment is established.

Research

Research costs are expensed as incurred.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use.

All other finance costs are recognized in the income statement in the period in which they are incurred.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

Adopted for 2008

Standards and interpretations adopted in the year had no significant impact on the financial statements.

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

IFRS 8 Operating Segments was issued in October 2006 and defines operating segments as components of an entity about which separate financial information is available and is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. The new standard sets out the required disclosures for operating segments and is effective for annual periods beginning on or after 1 January 2009. BP will adopt the new standard with effect from 1 January 2009 and expects no change to its segments that are separately reported but anticipates that its segmental analysis will be based on non-GAAP measures as used by the chief operating decision maker. There will be no effect on the group s reported income or net assets. IFRS 8 has been adopted by the EU.

In September 2007, the IASB issued Amendments to IAS 1 Presentation of Financial Statements A Revised Presentation, which requires separate presentation of owner and non-owner changes in equity by introducing the statement of comprehensive income. The statement of recognized income and expense will no longer be presented. Whenever there is a restatement or reclassification, an additional balance sheet, as at the beginning of the earliest period presented, will be required to be published. The revised standard is effective for annual periods beginning on or after 1 January 2009 and BP will adopt it from that date. There will be no effect on the group s reported income or net assets. IAS 1 Revised has been adopted by the EU.

In January 2008, the IASB issued a revised version of IFRS 3 Business Combinations . The revised standard still requires the purchase method of accounting to be applied to business combinations but will introduce some changes to existing accounting treatment. For example, contingent consideration is measured at fair value at the date of acquisition and subsequently remeasured to fair value with changes recognized in profit or loss. Goodwill may be calculated based on the parent s share of net assets or it may include goodwill related to the minority interest. All transaction costs are expensed. The standard is applicable to business combinations occurring in accounting periods beginning on or after 1 July 2009 and BP plans to adopt it with effect from 1 January 2010. Assets and liabilities arising from business combinations occurring before the date of adoption by the group will not be restated and thus there will be no effect on the group s reported income or net assets on adoption. The revised standard has not yet been adopted by the EU.

Also in January 2008, the IASB issued an amended version of IAS 27 Consolidated and Separate Financial Statements . This requires the effects of all transactions with non-controlling interests to be recorded in equity if there is no change in control. Such transactions will no longer result in goodwill or gains or losses. When control is lost, any remaining interest in the entity is remeasured to fair value and a gain or loss recognized in profit or loss. The amendment is effective for annual periods beginning on or after 1 July 2009 and is to be applied retrospectively, with certain exceptions. BP plans to adopt the amendment with effect from 1 January 2010 and has not yet completed its evaluation of the effect of adoption. The revised standard has not yet been adopted by the EU.

In addition, IFRIC 18 Transfers of Assets from Customers was issued in January 2009 and is effective prospectively from 1 July 2009. BP has not yet completed its evaluation of the effect of adopting this interpretation.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

Notes on financial statements

2. Resegmentation

With effect from 1 January 2008 the organizational structure of BP has been simplified into two business segments Exploration and Production and Refining and Marketing. A separate business, Alternative Energy, handles BP s low-carbon businesses and future growth options outside oil and gas, including solar, wind, gas-fired power, hydrogen, biofuels and coal conversion.

As a result, and with effect from 1 January 2008:

The Gas, Power and Renewables segment ceased to report separately.

The natural gas liquids (NGLs), liquefied natural gas and gas and power marketing and trading businesses were transferred from the Gas, Power and Renewables segment to the Exploration and Production segment.

The Alternative Energy business was transferred from the Gas, Power and Renewables segment to Other businesses and corporate.

The Emerging Consumers Marketing Unit was transferred from Refining and Marketing to Alternative Energy.

The Biofuels business was transferred from Refining and Marketing to Alternative Energy.

The Shipping business was transferred from Refining and Marketing to Other businesses and corporate.

As a result of the transfers identified above, Other businesses and corporate has been redefined. It now consists of the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which includes interest income on the group s cash and cash equivalents) and corporate activities worldwide.

Comparative amounts have been restated to reflect the resegmentation, as shown below.

						$ million
						2007
By business - as reported	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Revenues						
Total revenues	57,941	251,538	21,725	1,010	(43,263)	288,951
Less: sales between businesses	(38,803)	(2,024)	(2,436)		43,263	
Total third party revenues	19,138	249,514	19,289	1,010		288,951
Segment results						
Profit (loss) before interest and tax	26,938	6,072	674	(1,128)	(204)	32,352
Segment assets and liabilities						

Segment assets	108,874	95,691	19,889	17,188	(6,271)	235,371
Segment liabilities	(23,792)	(41,053)	(13,439)	(14,940)	5,342	(87,882)
By business as restated						
Revenues						
Total revenues	69,376	250,897		3,972	(35,294)	288,951
Less: sales between businesses	(32,083)	(1,914)		(1,297)	35,294	
Total third party revenues	37,293	248,983		2,675		288,951
Segment results						
Profit (loss) before interest and tax	27,729	6,076		(1,233)	(220)	32,352
Segment assets and liabilities						
Segment assets	125,736	95,311		20,595	(6,271)	235,371
Segment liabilities	(37,741)	(41,409)		(14,074)	5,342	(87,882)

$ million

2006

By business - as reported	Exploration and Production	Refining and Marketing	Gas, Power and Renewables	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Total continuing operations
Revenues								
Total revenues	56,400	233,302	23,923	1,243	(44,266)	270,602		270,602
Less: sales between businesses	(36,171)	(4,076)	(4,019)		44,266			
Total third party revenues	20,229	229,226	19,904	1,243		270,602		270,602
Segment results								
Profit (loss) before interest and tax	29,629	5,541	1,321	(1,069)	52	35,474	184	35,658
By business as restated								
Revenues								
Total revenues	71,868	232,833		3,703	(37,802)	270,602		270,602
	(32,608)	(3,935)		(1,259)	37,802			

Less: sales between businesses							
Total third party revenues	39,260	228,898	2,444		270,602		270,602
Segment results							
Profit (loss) before interest and tax	30,953	5,419	(963)	65	35,474	184	35,658

Notes on financial statements

3. Acquisitions

Acquisitions in 2008

BP made a number of acquisitions in 2008 for a total consideration of $403 million. These business combinations were in the Exploration and Production segment and Other businesses and corporate and the most significant was the acquisition of Whiting Clean Energy, a cogeneration power plant. Fair value adjustments have been made on a provisional basis to the acquired assets and liabilities. Goodwill of $1 million has been recognized on these acquisitions.

Acquisitions in 2007

BP made a number of acquisitions in 2007 for a total consideration of $1,200 million. These business combinations were predominantly in the Refining and Marketing segment, the most significant of which was the acquisition of Chevron s Netherlands manufacturing company, Texaco Raffiniderij Pernis B.V. The acquisition included Chevron s 31% minority shareholding in Nerefco, its 31% shareholding in the 22.5 MW wind farm co-located at the refinery as well as a 22.8% shareholding in the TEAM joint venture terminal and shareholdings in two local pipelines linking the TEAM terminal to the refinery. Fair value adjustments were made to the acquired assets and liabilities. Goodwill of $270 million arose on these acquisitions.

Acquisitions in 2006

BP made a number of acquisitions in 2006 for a total consideration of $256 million. All these business combinations were in Other businesses and corporate. Fair value adjustments were made to the acquired assets and liabilities and goodwill of $64 million arose on these acquisitions.

4. Non-current assets held for sale and discontinued operations

Non-current assets held for sale

In December 2007, BP signed a memorandum of understanding with Husky Energy Inc. to form an integrated North American oil sands business. The transaction was completed on 31 March 2008, with BP contributing its Toledo refinery to a US jointly controlled entity to which Husky contributed $250 million cash and a payable of $2,588 million. The Toledo refinery assets and associated liabilities were classified as a disposal group held for sale at 31 December 2007. No impairment loss was recognized at the time of reclassification of the Toledo disposal group as held for sale nor at 31 December 2007. For further information see Notes 5 and 26.

The major classes of assets and liabilities of the Toledo disposal group, reported within the Refining and Marketing segment, classified as held for sale at 31 December 2007, are set out below.

	$ million
	2007
Assets	
Property, plant and equipment	635
Goodwill	90
Inventories	561
Assets classified as held for sale	1,286
Liabilities	
Current liabilities	163
Liabilities directly associated with assets classified as held for sale	163

Discontinued operations

The sale of Innovene, BP s olefins, derivatives and refining group, to INEOS was completed on 16 December 2005. In 2006 a loss before taxation of $184 million was incurred which related to post-closing adjustments. These adjustments also reduced disposal proceeds by $34 million.

Financial information for the Innovene operations after group eliminations is presented below.

	$ million
	2006
Loss recognized on the remeasurement to fair value less costs to sell and on disposal	(184)
Loss before taxation from Innovene operations	(184)
Tax (charge) credit	
on loss before loss recognized on remeasurement to fair value less costs to sell and on disposal	166
on loss recognized on the remeasurement to fair value less costs to sell and on disposal	(7)
Loss from Innovene operations	(25)
Loss per share from Innovene operations cents	
Basic	(0.13)
Diluted	(0.12)

Further information is contained in Note 5.

Notes on financial statements

5. Disposals

			$ million
	2008	2007	2006
Proceeds from the sale of Innovene operations			(34)
Proceeds from the sale of other businesses	**11**	2,518	325
Proceeds from the sale of businesses	**11**	2,518	291
Proceeds from disposal of fixed assets	**918**	1,749	5,963
	929	4,267	6,254
By business			
Exploration and Production	**19**	1,280	4,302
Refining and Marketing	**813**	2,953	1,784
Other businesses and corporate	**97**	34	168
	929	4,267	6,254

As part of the strategy to upgrade the quality of its asset portfolio, the group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. The group may also dispose of other assets, such as refineries, when this meets strategic objectives.

Cash received during the year from disposals amounted to $929 million (2007 $4.3 billion and 2006 $6.3 billion).

The major transactions in 2008 were the disposal of our Toledo refinery to an entity which we jointly control in the US and our continued disposal of company-owned and company-operated retail sites in the US.

The major transactions in 2007 were the disposals of our Coryton refinery, our exploration and production and gas infrastructure business in the Netherlands, our interest in non-core Permian assets in the US and our interest in the Entrada field in the Gulf of Mexico.

The major transactions in 2006 were the disposals of our interests in the Gulf of Mexico Shelf and our interest in the Shenzi discovery in the Gulf of Mexico. The principal transactions for each business segment are described below.

Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. There were no significant disposals in 2008.

During 2007, the major transactions were the disposal of an exploration and production and gas infrastructure business in the Netherlands and the divestments of our interests in non-core Permian assets in the US and in the Entrada field in the Gulf of Mexico. We also sold our interests in a number of fields in Egypt, Canada and the US.

During 2006, the major transactions were disposals of our interests in the Gulf of Mexico Shelf, in the Shenzi discovery in the Gulf of Mexico, in the Statfjord oil and gas field and in the Luva gas field in the North Sea. We also divested our interests in a number of onshore fields in South Louisiana, interests in fields in the North Sea, the Gulf of Suez and Venezuela, part of an interest in Colombia and our shareholding in Enagas, the Spanish gas transport grid operator.

Refining and Marketing

The churn of retail assets represents a significant element of the total in all three years and in particular, in 2008, our continued disposal of sites in the US. In addition, in 2008 we contributed our Toledo refinery to a US jointly controlled entity in an exchange transaction with Husky Energy and disposed of our interest in the Dixie Pipeline in the US, certain assets at our Acetyls plant in Hull, UK, and other interests in the UK and Europe.

During 2007, we disposed of the Coryton refinery in the UK, our interest in the West Texas Pipeline in the US, our interest in the Samsung Petrochemical Company in South Korea and other interests in France, Brazil and Africa.

During 2006, we disposed of our interests in Zhenhai Refining and Chemicals Company in China and in Eiffage, the French-based construction company. We also exited the retail market in the Czech Republic and disposed of our interests in a number of pipelines.

Notes on financial statements

5. Disposals continued

Other businesses and corporate

In 2008, the group disposed of miscellaneous non-core assets.

There were no significant disposals in 2007. During 2006, the group disposed of miscellaneous non-core businesses and assets.

Summarized financial information for the sale of businesses is shown below.

			$ million
	2008	2007	2006
The disposals comprise the following			
Non-current assets	**759**	753	143
Current assets	**485**	587	169
Non-current liabilities		(64)	(10)
Current liabilities	**(134)**	(27)	(70)
Total carrying amount of net assets disposed	**1,110**	1,249	232
Recycling of foreign exchange on disposal		(147)	
Costs on disposal	**7**	22	
	1,117	1,124	232
Profit (loss) on sale of businesses[a]	**1,721**	1,384	167
Total consideration	**2,838**	2,508	399
Fair value of interest received in a jointly controlled entity	**(2,838)**		
Consideration received (receivable)[b]	**11**	10	(74)
Closing adjustments associated with the sale of Innovene			(34)
Proceeds from the sale of businesses[c]	**11**	2,518	291

[a]Of which $929 million gain has not been recognized in the income statement in 2008 as it represents an unrealized gain on the transfer of the Toledo refinery into a jointly controlled entity.

[b]Consideration received from prior year disposals or not yet received from current year disposals.

[c]Net of cash and cash equivalents disposed of nil (2007 $115 million and 2006 $2 million).

Notes on financial statements

6. Segmental analysis

The group s primary format for segment reporting is business segments and the secondary format is geographical segments. The risks and returns of the group s operations are primarily determined by the nature of the different activities that the group engages in, rather than the geographical location of these operations. This is reflected by the group s organizational structure and internal financial reporting systems.

In 2008, BP had two reportable operating segments: Exploration and Production and Refining and Marketing. Exploration and Production s activities include oil and natural gas exploration, development and production (upstream activities), together with related pipeline, transportation and processing activities (midstream activities), as well as the marketing and trading of natural gas (including LNG), power and natural gas liquids (NGLs). The activities of Refining and Marketing include the supply and trading, refining, manufacturing, marketing and transportation of crude oil, petroleum and chemicals products and related services. The group is managed on an integrated basis.

Other businesses and corporate comprises the Alternative Energy business, Shipping, the group s aluminium asset, Treasury (which in the segmental analysis includes all of the group s cash, cash equivalents and associated interest income), and corporate activities worldwide.

The accounting policies of the operating segments are the same as the group s accounting policies described in Note 1.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred.

The group s geographical segments are based on the location of the group s assets. The UK and the US are significant countries of activity for the group; the other geographical segments are groupings of countries determined by geographical location.

Sales to external customers are based on the location of the seller, which in most circumstances is not materially different from the location of the customer. Crude oil and LNG are commodities for which there is an international market and buyers and sellers can be widely separated geographically. The UK segment includes the UK-based international activities of Refining and Marketing.

$ million

					2008
By business	**Exploration and Production**	**Refining and Marketing**	**Other businesses and corporate**	**Consolidation adjustment and eliminations**	**Total group**
Sales and other operating revenues					
Segment sales and other operating revenues	**86,170**	**320,039**	**4,634**	**(49,700)**	**361,143**
Less: sales between businesses	**(45,931)**	**(1,918)**	**(1,851)**	**49,700**	
Third party sales	**40,239**	**318,121**	**2,783**		**361,143**
Equity-accounted earnings	**3,565**	**131**	**125**		**3,821**
Interest and other revenues	**167**	**288**	**281**		**736**

Total revenues	**43,971**	**318,540**	**3,189**		**365,700**
Segment results					
Profit (loss) before interest and taxation	**37,915**	**(1,884)**	**(1,258)**	**466**	**35,239**
Finance costs and net finance income relating to pensions and other post-retirement benefits				**(956)**	**(956)**
Profit (loss) before taxation	**37,915**	**(1,884)**	**(1,258)**	**(490)**	**34,283**
Taxation				**(12,617)**	**(12,617)**
Profit (loss) for the year	**37,915**	**(1,884)**	**(1,258)**	**(13,107)**	**21,666**
Assets and liabilities					
Segment assets	**136,665**	**75,329**	**19,079**	**(3,212)**	**227,861**
Current tax receivable				**377**	**377**
Total assets	**136,665**	**75,329**	**19,079**	**(2,835)**	**228,238**
Includes					
Equity-accounted investments	**20,131**	**6,622**	**1,073**		**27,826**
Segment liabilities	**(39,611)**	**(28,668)**	**(18,218)**	**2,914**	**(83,583)**
Current tax payable				**(3,144)**	**(3,144)**
Finance debt				**(33,204)**	**(33,204)**
Deferred tax liabilities				**(16,198)**	**(16,198)**
Total liabilities	**(39,611)**	**(28,668)**	**(18,218)**	**(49,632)**	**(136,129)**
Other segment information					
Capital expenditure and acquisitions					
Goodwill and other intangible assets	**4,940**	**145**	**89**		**5,174**
Property, plant and equipment	**14,117**	**4,417**	**959**		**19,493**
Other	**3,170**	**2,072**	**791**		**6,033**
Total	**22,227**	**6,634**	**1,839**		**30,700**
Depreciation, depletion and amortization	**8,440**	**2,208**	**337**		**10,985**
Impairment losses	**1,186**	**159**	**227**		**1,572**
Impairment reversals	**155**				**155**
Losses on sale of businesses and fixed assets	**18**	**297**	**1**		**316**
Gains on sale of businesses and fixed assets	**34**	**1,258**	**61**		**1,353**

Notes on financial statements

6. Segmental analysis continued

					$ million
					2007
By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
Sales and other operating revenues					
Segment sales and other operating revenues	65,740	250,221	3,698	(35,294)	284,365
Less: sales between businesses	(32,083)	(1,914)	(1,297)	35,294	
Third party sales	33,657	248,307	2,401		284,365
Equity-accounted earnings	3,199	542	91		3,832
Interest and other revenues	437	134	183		754
Total revenues	37,293	248,983	2,675		288,951
Segment results					
Profit (loss) before interest and taxation	27,729	6,076	(1,233)	(220)	32,352
Finance costs and net finance income relating to pensions and other post-retirement benefits				(741)	(741)
Profit (loss) before taxation	27,729	6,076	(1,233)	(961)	31,611
Taxation				(10,442)	(10,442)
Profit (loss) for the year	27,729	6,076	(1,233)	(11,403)	21,169
Assets and liabilities					
Segment assets	125,736	95,311	20,595	(6,271)	235,371
Current tax receivable				705	705
Total assets	125,736	95,311	20,595	(5,566)	236,076
Includes					
Equity-accounted investments	16,770	5,268	654		22,692
Segment liabilities	(37,741)	(41,409)	(14,074)	5,342	(87,882)
Current tax payable				(3,282)	(3,282)
Finance debt				(31,045)	(31,045)

Deferred tax liabilities				(19,215)	(19,215)
Total liabilities	(37,741)	(41,409)	(14,074)	(48,200)	(141,424)
Other segment information					
Capital expenditure and acquisitions					
Goodwill and other intangible assets	2,245	581	27		2,853
Property, plant and equipment	11,539	4,474	874		16,887
Other	423	440	38		901
Total	14,207	5,495	939		20,641
Depreciation, depletion and amortization	7,856	2,421	302		10,579
Impairment losses	292	1,186	83		1,561
Impairment reversals	237				237
Losses on sale of businesses and fixed assets	42	313			355
Gains on sale of businesses and fixed assets	954	1,464	69		2,487

Notes on financial statements

6. Segmental analysis continued

$ million

2006

By business	Exploration and Production	Refining and Marketing	Other businesses and corporate	Consolidation adjustment and eliminations	Total group	Innovene operations	Total continuing operations
Sales and other operating revenues							
Segment sales and other operating revenues	67,950	232,386	3,372	(37,802)	265,906		265,906
Less: sales between businesses	(32,608)	(3,935)	(1,259)	37,802			
Third party sales	35,342	228,451	2,113		265,906		265,906
Equity-accounted earnings	3,568	341	86		3,995		3,995
Interest and other revenues	350	106	245		701		701
Total revenues	39,260	228,898	2,444		270,602		270,602
Segment results							
Profit (loss) before interest and taxation	30,953	5,419	(963)	65	35,474	184	35,658
Finance costs and net finance income relating to pensions and other post-retirement benefits				(516)	(516)		(516)
Profit (loss) before taxation	30,953	5,419	(963)	(451)	34,958	184	35,142
Taxation				(12,357)	(12,357)	(159)	(12,516)
Profit (loss) for the year	30,953	5,419	(963)	(12,808)	22,601	25	22,626
Other segment information							
Depreciation, depletion and amortization	6,689	2,239	200		9,128		9,128
Impairment losses	237	155	69		461		461
Impairment reversals	340				340		340
Loss on remeasurement to fair value less costs to sell and on			184		184	(184)	

disposal of Innovene operations					
Losses on sale of businesses and fixed assets	195	228	5	428	428
Gains on sale of businesses and fixed assets	2,502	1,109	103	3,714	3,714

Notes on financial statements

6. Segmental analysis continued

$ million

						2008
By geographical area	**UK**	**Rest of Europe**	**US**	**Rest of World**	**Consolidation adjustment and eliminations**	**Total**
Sales and other operating revenues						
Segment sales and other operating revenues	**150,133**	**93,303**	**130,142**	**105,911**		**479,489**
Less: sales between areas	**(68,360)**	**(11,272)**	**(6,778)**	**(31,936)**		**(118,346)**
Third party sales	**81,773**	**82,031**	**123,364**	**73,975**		**361,143**
Equity-accounted earnings	**(4)**	**74**	**(14)**	**3,765**		**3,821**
Interest and other revenues	**55**	**226**	**193**	**262**		**736**
Total revenues	**81,824**	**82,331**	**123,543**	**78,002**		**365,700**
Segment results						
Profit before interest and taxation	**5,808**	**1,541**	**7,831**	**20,059**		**35,239**
Finance costs and net finance income relating to pensions and other post-retirement benefits	**(22)**	**(316)**	**(411)**	**(207)**		**(956)**
Profit before taxation	**5,786**	**1,225**	**7,420**	**19,852**		**34,283**
Taxation	**(2,867)**	**(576)**	**(2,336)**	**(6,838)**		**(12,617)**
Profit for the year	**2,919**	**649**	**5,084**	**13,014**		**21,666**
Assets and liabilities						
Segment assets	**40,693**	**27,999**	**87,364**	**80,090**	**(8,285)**	**227,861**
Current tax receivable	**1**	**187**	**125**	**64**		**377**
Total assets	**40,694**	**28,186**	**87,489**	**80,154**	**(8,285)**	**228,238**
Includes						
Equity-accounted investments	**92**	**1,873**	**3,790**	**22,071**		**27,826**
Segment liabilities	**(23,767)**	**(14,319)**	**(33,099)**	**(20,683)**	**8,285**	**(83,583)**

Current tax payable	**(438)**	**(399)**	**(881)**	**(1,426)**		**(3,144)**
Finance debt	**(22,621)**	**(201)**	**(7,659)**	**(2,723)**		**(33,204)**
Deferred tax liabilities	**(2,031)**	**(862)**	**(8,916)**	**(4,389)**		**(16,198)**
Total liabilities	**(48,857)**	**(15,781)**	**(50,555)**	**(29,221)**	**8,285**	**(136,129)**
Other segment information						
Capital expenditure and acquisitions						
Goodwill and other intangible assets	**277**	**19**	**3,794**	**1,084**		**5,174**
Property, plant and equipment	**1,279**	**2,043**	**9,655**	**6,516**		**19,493**
Other	**52**	**125**	**2,597**	**3,259**		**6,033**
Total	**1,608**	**2,187**	**16,046**	**10,859**		**30,700**
Depreciation, depletion and amortization	**1,610**	**997**	**3,969**	**4,409**		**10,985**
Exploration expense	**121**	**1**	**306**	**454**		**882**
Impairment losses	**97**	**104**	**392**	**979**		**1,572**
Impairment reversals			**9**	**146**		**155**
Losses on sale of businesses and fixed assets	**1**	**23**	**259**	**33**		**316**
Gains on sale of businesses and fixed assets	**74**	**49**	**1,209**	**21**		**1,353**

Notes on financial statements

6. Segmental analysis continued

						$ million
						2007
By geographical area	UK	Rest of Europe	US	Rest of World	Consolidation adjustment and eliminations	Total
Sales and other operating revenues						
Segment sales and other operating revenues	109,800	78,366	105,120	74,462		367,748
Less: sales between areas	(48,651)	(12,024)	(2,801)	(19,907)		(83,383)
Third party sales	61,149	66,342	102,319	54,555		284,365
Equity-accounted earnings	1	55	144	3,632		3,832
Interest and other revenues	222	78	142	312		754
Total revenues	61,372	66,475	102,605	58,499		288,951
Segment results						
Profit before interest and taxation	4,613	4,164	7,439	16,136		32,352
Finance costs and net finance income relating to pensions and other post-retirement benefits	(17)	(287)	(524)	87		(741)
Profit before taxation	4,596	3,877	6,915	16,223		31,611
Taxation	(2,027)	(949)	(2,593)	(4,873)		(10,442)
Profit for the year	2,569	2,928	4,322	11,350		21,169
Assets and liabilities						
Segment assets	53,065	34,658	81,911	76,504	(10,767)	235,371
Current tax receivable	3	27	468	207		705
Total assets	53,068	34,685	82,379	76,711	(10,767)	236,076
Includes						
Equity-accounted investments	142	1,970	1,659	18,921		22,692
Segment liabilities	(30,043)	(18,985)	(31,314)	(18,307)	10,767	(87,882)

Current tax payable	(963)	(658)	(104)	(1,557)		(3,282)
Finance debt	(20,085)	(200)	(8,238)	(2,522)		(31,045)
Deferred tax liabilities	(3,397)	(1,124)	(10,656)	(4,038)		(19,215)
Total liabilities	(54,488)	(20,967)	(50,312)	(26,424)	10,767	(141,424)
Other segment information						
Capital expenditure and acquisitions						
Goodwill and other intangible assets	453	298	817	1,285		2,853
Property, plant and equipment	1,141	2,489	6,516	6,741		16,887
Other	78	253	154	416		901
Total	1,672	3,040	7,487	8,442		20,641
Depreciation, depletion and amortization	2,133	959	3,558	3,929		10,579
Exploration expense	46		252	458		756
Impairment losses	315	136	723	387		1,561
Impairment reversals			237			237
Losses on sale of businesses and fixed assets	2	77	233	43		355
Gains on sale of businesses and fixed assets	893	655	770	169		2,487

Notes on financial statements

6. Segmental analysis continued

					$ million
					2006
By geographical area	UK	Rest of Europe	US	Rest of World	Total
Sales and other operating revenues					
Segment sales and other operating revenues	105,518	76,768	99,935	71,547	353,768
Less: sales between areas	(50,942)	(14,821)	(5,032)	(17,067)	(87,862)
Third party sales	54,576	61,947	94,903	54,480	265,906
Equity-accounted earnings	5	13	127	3,850	3,995
Interest and other revenues	258	7	107	329	701
Total revenues	54,839	61,967	95,137	58,659	270,602
Segment results					
Profit before interest and taxation from continuing operations	5,897	3,282	11,664	14,815	35,658
Finance costs and net finance income relating to pensions and other post-retirement benefits	43	(262)	(331)	34	(516)
Profit before taxation from continuing operations	5,940	3,020	11,333	14,849	35,142
Taxation	(3,158)	(1,176)	(3,738)	(4,444)	(12,516)
Profit for the year from continuing operations	2,782	1,844	7,595	10,405	22,626
Profit (loss) from Innovene operations	31	(76)	(2)	22	(25)
Profit for the year	2,813	1,768	7,593	10,427	22,601
Other segment information					
Depreciation, depletion and amortization	2,139	840	3,459	2,690	9,128
Exploration expense	20		633	392	1,045
Impairment losses		171	114	176	461
Impairment reversals	176		90	74	340
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations	185	36	(16)	(21)	184
Losses on sale of businesses and fixed assets	12	96	217	103	428
Gains on sale of businesses and fixed assets	337	577	2,530	270	3,714

Notes on financial statements

7. Interest and other revenues

			$ million
	2008	2007	2006
Related to financial instruments			
Interest income from available-for-sale financial assets	**32**	5	13
Dividend income from available-for-sale financial assets	**37**	29	32
Interest income from loans and receivables	**163**	175	186
	232	209	231
Not related to financial instruments			
Interest from loans to equity-accounted entities	**115**	172	176
Other interest	**59**	97	62
Other income	**330**	276	232
	504	545	470
	736	754	701

8. Gains on sale of businesses and fixed assets

			$ million
	2008	2007	2006
Gains on sale of businesses			
Exploration and Production		527	
Refining and Marketing	**792**	850	101
Other businesses and corporate		7	66
	792	1,384	167
Gains on sale of fixed assets			
Exploration and Production	**34**	427	2,502
Refining and Marketing	**466**	614	1,008
Other businesses and corporate	**61**	62	37
	561	1,103	3,547
	1,353	2,487	3,714

The principal transactions giving rise to these gains for each business segment are described below.

Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. There were no significant divestments during 2008.

The major divestments during 2007 that resulted in gains were the disposal of an exploration and production and gas infrastructure business in the Netherlands and the divestments of our interests in non-core Permian assets in the US and in the Entrada field in the Gulf of Mexico.

The major divestments during 2006 that resulted in gains were the sales of our interest in the Shenzi discovery in the Gulf of Mexico in the US, interests in the North Sea and our shareholding in Enagas.

Refining and Marketing

During 2008, the major divestments that resulted in gains were the disposal of US retail assets, the contribution of Toledo refinery to a jointly controlled entity with Husky Energy and the disposal of our interest in the Dixie Pipeline.

During 2007, the major transactions that resulted in gains were the divestment of Coryton refinery in the UK, the interest in the West Texas Pipeline in the US and the interest in the Samsung Petrochemical Company in South Korea.

During 2006, the major transactions that resulted in gains were the divestment of the retail business in the Czech Republic and fixed assets including the shareholding in Zhenhai Refining and Chemicals Company in China, the shareholding in Eiffage, the French-based construction company, and pipeline assets.

Other businesses and corporate

There were no significant disposals in 2008 and 2007.

During 2006, the group disposed of its ethylene oxide business.

Additional information on the sale of businesses and fixed assets is given in Note 5.

Notes on financial statements

9. Production and similar taxes

			$ million
	2008	2007	2006
UK	**370**	197	260
Overseas	**6,156**	3,816	3,361
	6,526	4,013	3,621

10. Depreciation, depletion and amortization

			$ million
By business	**2008**	2007	2006
Exploration and Production[a]			
UK	**1,168**	1,698	1,735
Rest of Europe	**203**	213	225
US	**3,012**	2,365	2,336
Rest of World	**4,057**	3,580	2,393
	8,440	7,856	6,689
Refining and Marketing			
UK[b]	**288**	278	299
Rest of Europe	**761**	729	603
US	**825**	1,076	1,047
Rest of World	**334**	338	290
	2,208	2,421	2,239
Other businesses and corporate			
UK	**154**	157	105
Rest of Europe	**33**	17	12
US	**132**	117	76
Rest of World	**18**	11	7
	337	302	200
By geographical area			
UK[b]	**1,610**	2,133	2,139

Rest of Europe	**997**	959	840
US	**3,969**	3,558	3,459
Rest of World	**4,409**	3,929	2,690
	10,985	10,579	9,128

[a]At the end of 2006, BP adopted the US Securities and Exchange Commission (SEC) rules for estimating oil and natural gas reserves instead of the UK accounting rules contained in the Statement of Recommended Practice Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities (UK SORP). This change in accounting estimate had a direct impact on the amount of depreciation, depletion and amortization (DD&A) charged in the income statement in respect of oil and natural gas properties which are depreciated on a unit-of-production basis as described in Note 1. The change in estimate was applied prospectively, with no restatement of prior periods results. The group s actual DD&A charge for 2006 was $9,128 million, whereas the charge based on UK SORP reserves would have been $9,057 million, i.e. an increase of $71 million due to the change in reserves estimates that was used to calculate DD&A for the last three months of 2006. For 2007, it was estimated that the DD&A charge would have increased by approximately $400 million to $500 million as a result of the change. No estimate has been made in respect of 2008. Over the life of a field, this change has no overall effect on DD&A. The main differences between the UK SORP and SEC rules relate to the SEC requirement to use year-end prices and costs, the application of SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e. gas used for fuel in operations) within proved reserves. Consequently, reserves quantities under SEC rules differ from those that would be reported under application of the UK SORP. The change to SEC reserves in 2006 represented a simplification of the group s reserves reporting, as only one set of reserves estimates is disclosed. In addition, the use of SEC reserves for accounting purposes makes our results more comparable with those of our major competitors.

[b]UK area includes the UK-based international activities of Refining and Marketing.

Notes on financial statements

11. Impairment and losses on sale of businesses and fixed assets

			$ million
	2008	2007	2006
Impairment losses			
Exploration and Production	**1,186**	292	237
Refining and Marketing	**159**	1,186	155
Other businesses and corporate	**227**	83	69
	1,572	1,561	461
Impairment reversals			
Exploration and Production	**(155)**	(237)	(340)
	(155)	(237)	(340)
Loss on sale of fixed assets			
Exploration and Production	**18**	42	195
Refining and Marketing	**297**	313	228
Other businesses and corporate	**1**		5
	316	355	428
Loss on remeasurement to fair value less costs to sell and on disposal of Innovene operations			184
	1,733	1,679	733
Innovene operations			(184)
Continuing operations	**1,733**	1,679	549

Impairment
In assessing whether a write-down is required in the carrying value of a potentially impaired intangible asset, item of property, plant and equipment or an equity-accounted investment, its carrying value is compared with its recoverable amount. The recoverable amount is the higher of the asset s fair value less costs to sell and value in use. Given the nature of the group s activities, information on the fair value of an asset is usually difficult to obtain unless negotiations with potential purchasers are taking place. Consequently, unless indicated otherwise, the recoverable amount used in assessing the impairment charges described below is value in use. The group estimates value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the asset and are discounted using a pre-tax discount rate. This discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. Typically rates of 11% or 13% are used (2007 11% or 13%). The rate to be applied for each country is reassessed each year. For impairments of available-for-sale financial assets that are quoted investments, the fair value is determined by reference to bid prices at the close of business at the balance sheet date. Any cumulative gain or loss previously recognized in equity is transferred to the income statement.

Exploration and Production

During 2008, the Exploration and Production segment recognized impairment losses of $1,186 million. The main elements were the writing down of our investment in Rosneft by $517 million to its fair value determined by reference to an active market, due to a significant decline in the market value of the investment, impairment of oil and gas properties in the Gulf of Mexico of $270 million triggered by downward revisions of reserves, an impairment of exploration assets in Vietnam of $210 million following BP s decision to withdraw from activities in the area concerned, impairment of oil and gas properties in Egypt of $85 million triggered by cost increases and several other individually insignificant impairment charges amounting to $104 million.

These charges were partly offset by reversals of previously recognized impairment charges amounting to $155 million. Of this total, $122 million resulted from a reassessment of the economics of Rhourde El Baguel in Algeria.

During 2007, the Exploration and Production segment recognized impairment losses of $292 million. The main elements were a charge of $112 million relating to the cancellation of the DF1 project in Scotland, a $103 million partner loan write-off as a result of unsuccessful drilling in the West Shmidt licence block in Sakhalin and a $52 million write-off of the Whitney Canyon gas plant in US Lower 48 driven by management s decision to abandon this facility. In addition, there were several individually insignificant impairment charges, triggered by downward reserves revisions, amounting to $25 million in total.

These charges were largely offset by reversals of previously recognized impairment charges amounting to $237 million. Of this total, $208 million resulted from a reassessment of the decommissioning liability for damaged platforms in the Gulf of Mexico Shelf. The remaining $29 million related to other individually insignificant impairment reversals, resulting from favourable revisions to the estimates used in determining the assets recoverable amounts.

During 2006, Exploration and Production recognized a net gain on impairment. The main element was a $340 million credit for reversals of previously booked impairments relating to the UK North Sea, US Lower 48 and China. These reversals resulted from a positive change in the estimates used to determine the assets recoverable amount since the impairment losses were recognized. This was partially offset by impairment losses totalling $237 million. The major element was a charge of $109 million against intangible assets relating to properties in Alaska. The trigger for the impairment test was the decision of the Alaska Department of Natural Resources to terminate the Point Thompson Unit Agreement. We are defending our right through the appeal process. In addition, there was a charge of $100 million relating to certain North American pipeline assets. The trigger for impairment testing was the reduction in future pipeline tariff revenues and increased ongoing operational costs. The remaining $28 million relates to other individually insignificant impairments, the impairment tests for which were triggered by downward reserves revisions and increased tax burden.

Notes on financial statements

11. Impairment and losses on sale of businesses and fixed assets continued

Refining and Marketing

During 2008, the Refining and Marketing segment recognized impairment losses on a number of assets which in total amounted to $159 million.

The main component of the 2007 impairment charge of $1,186 million arose because of a decision to sell our company-owned and company-operated sites in the US resulting in a $610 million write-down of the carrying amount of the sites to fair value less costs to sell. Following a decision to sell certain assets at our Acetyls plant in Hull, UK, we wrote down the carrying amount of these assets to fair value less costs to sell leading to an impairment charge of $186 million. Changing marketing conditions led to impairments in Samsung Petrochemical Company, to fair value less costs to sell, and in China American Petrochemical Company amounting in total to $165 million. The balance relates principally to the write-downs of assets elsewhere in the segment portfolio.

During 2006, certain assets in our Retail and Aromatics & Acetyls businesses were written down to fair value less costs to sell.

Other businesses and corporate

During 2008, Other businesses and corporate recognized impairment losses totalling $227 million primarily related to various assets in the Alternative Energy business.

There were no significant impairments in 2007.

The impairment charge for 2006 relates to remaining chemical assets after the sale of Innovene.

Loss on sale of fixed assets

The principal transactions that give rise to the losses for each business segment are described below.

Exploration and Production

The group divested interests in a number of oil and natural gas properties in all three years. For 2006, the largest component of the loss is attributed to the sale of properties in the Gulf of Mexico Shelf, which included increases in decommissioning liability estimates associated with the hurricane-damaged fields that were divested during the year.

Refining and Marketing

For 2008, the principal transactions contributing to the loss were disposals of retail sites in the US and Europe.

For 2007, the principal transactions contributing to the loss were related to the decision to withdraw from the company-owned and company-operated channel of trade in the US and retail churn. Retail churn is the overall process of acquiring and disposing of retail sites by which the group aims to improve the quality and mix of its portfolio of service stations.

For 2006, the principal transactions contributing to the loss were retail churn.

12. Impairment review of goodwill

		$ million
Goodwill at 31 December	**2008**	2007
Exploration and Production	**4,297**	4,296
Refining and Marketing	**5,462**	6,626
Other businesses and corporate	**119**	84
	9,878	11,006

Goodwill acquired through business combinations has been allocated to groups of cash-generating units (cash-generating units) that are expected to benefit from the synergies of the acquisition. For Exploration and Production, goodwill has been allocated to each geographic region, that is UK, Rest of Europe, US and Rest of World, and for Refining and Marketing, goodwill has been allocated to the Rhine Fuels Value Chain (FVC), US West Coast FVC, Lubricants and Other.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (including goodwill) is compared with the recoverable amount of the cash-generating unit. The recoverable amount is the higher of fair value less costs to sell and value in use. In the absence of any information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use.

The group calculates the recoverable amount as the value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group s post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. Typically rates of 11% or 13% are used (2007 11% or 13%). The rate to be applied to each country is reassessed each year. A discount rate of 11% has been used for all goodwill impairment calculations performed in 2008 (2007 11%).

The three-year or four-year business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various environmental assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These environmental assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability.

For the purposes of impairment testing, the group s Brent oil price assumption is an average $49 per barrel in 2009, $59 per barrel in 2010, $65 per barrel in 2011, $68 per barrel in 2012, $70 per barrel in 2013 and $75 per barrel in 2014 and beyond (2007 average $90 per barrel in 2008, $86 per barrel in 2009, $84 per barrel in 2010, $84 per barrel in 2011, $84 per barrel in 2012 and $60 per barrel in 2013 and beyond). Similarly, the

Notes on financial statements

12. Impairment review of goodwill continued
group s assumption for Henry Hub natural gas prices is an average of $6.16/mmBtu in 2009, $7.15/mmBtu in 2010, $7.34/mmBtu in 2011, $7.62/mmBtu in 2012, $7.60/mmBtu in 2013 and $7.50/mmBtu in 2014 and beyond (2007 average of $7.87/mmBtu in 2008, $8.33/mmBtu in 2009, $8.26/mmBtu in 2010, $8.12/mmBtu in 2011, $8.00/mmBtu in 2012 and $7.50/mmBtu in 2013 and beyond). The prices for the first five years are derived from forward price curves at the year-end. Prices in 2014 and beyond are determined using long-term views of global supply and demand, building upon past experience of the industry and consistent with a number of external economic forecasts. These prices are adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas.

Exploration and Production

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field. Management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment, as the production profile and related cash flows can be estimated from the company s past experience. The date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, the production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP s management for the purpose. Capital expenditure and operating costs for the first four years and expected hydrocarbon production profiles up to 2020 are derived from the business segment plan. Estimated production quantities and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the resource volumes approved as part of BP s centrally-controlled process for the estimation of proved reserves and total resources.

Consistent with prior years, the 2008 review for impairment was carried out during the fourth quarter. Detailed calculations were performed for the US and the UK. As permitted by IAS 36, the detailed calculations performed in 2005 were used for the 2008 impairment test on the goodwill for the Rest of World as the criteria of IAS 36 were considered to be satisfied: the excess of the recoverable amount over the carrying amount was substantial in 2005; there had been no significant change in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time of the test was remote.

The following table shows the carrying amount of the goodwill allocated to each of the regions of the Exploration and Production segment and, for the US and the UK, the amount by which the recoverable amount (value in use) exceeds the carrying amount of the goodwill and other non-current assets in the cash-generating units to which the goodwill has been allocated. No impairment charge is required.

The key assumptions required for the value-in-use estimation are the oil and natural gas prices, production volumes and the discount rate. To test the sensitivity of the excess of the recoverable amount over the carrying amount of goodwill and other non-current assets (the headroom) to changes in production volumes and oil and natural gas prices, management has developed rules of thumb for key assumptions. Applying these gives an indication of the impact on the headroom of possible changes in the key assumptions.

It is estimated that the long-term price of oil that would cause the total recoverable amount to be equal to the total carrying amount for each cash-generating unit would be of the order of $38 per barrel for the UK and $50 per barrel for the US. It was estimated that the long-term price of gas that would cause the total recoverable amount to be equal to the total carrying amount of goodwill and related non-current assets for the US cash-generating unit would be of the order of $4/mmBtu (Henry Hub). As a significant amount of gas from the North Sea is sold under fixed-price contracts, or contracts priced using non-gas indices, it is estimated that no reasonably possible change in gas prices would cause the UK headroom to be reduced to zero. It was estimated that no reasonably possible change in oil and gas prices would cause the headroom in Rest of World to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields agreed by management as part of the long-term planning process. It is estimated that, if all our production were to be reduced by 10% for the whole of the next 15 years, this would not be sufficient to reduce the excess of recoverable amount over the carrying amounts of each cash-generating unit to zero. Consequently, management believes no reasonably possible change in the production assumption would cause the carrying amounts to exceed the recoverable amounts.

Management also believes that currently there is no reasonably possible change in discount rate that would cause the carrying amounts in the UK, US or Rest of World to exceed the recoverable amounts.

				$ million
				2008
	UK	**US**	**Rest of World**	**Total**
Goodwill	**341**	**3,441**	**515**	**4,297**
Excess of recoverable amount over carrying amount	**7,972**	**16,692**	**n/a**	**n/a**

				$ million
				2007
	UK	US	Rest of World	Total
Goodwill	341	3,440	515	4,296

Notes on financial statements

12. Impairment review of goodwill continued

Refining and Marketing

In previous years, Refining and Marketing goodwill has been allocated to the following cash-generating units: Refining, Retail, Lubricants, and Other. In 2008, the Refining and Retail units were largely integrated into geographically-based Fuels Value Chain units (FVC) and consequently the cash-generating units to which goodwill is allocated have been redefined. The goodwill previously allocated to the global Refining and Retail units has been aggregated and reallocated to the FVC units that are expected to benefit from the synergies of the business combinations that gave rise to the goodwill. As part of this reallocation a small amount of goodwill was also allocated to business units included in Other . Goodwill is now allocated to the following cash-generating units: Rhine FVC, US West Coast FVC, Lubricants and Other.

For all cash-generating units, the cash flows for the first three years are derived from the three-year business segment plan. For determining the value in use for each of the cash-generating units, cash flows for a period of 10 years have been discounted and aggregated with a terminal value. A key assumption for the FVCs is the Global Indicator Margin (GIM). Each regional GIM is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity.

Rhine FVC

Cash flows beyond the three-year period are extrapolated using a 1.2% growth rate.

The key assumptions to which the calculation of value in use for the Rhine FVC unit is most sensitive are refinery gross margins, refinery production volumes and discount rate. The average value assigned to the refinery gross margin during the plan period is based on a $5.50 per barrel GIM. The average value assigned to the refinery production volume is 250mmbbl a year over the plan period. These key assumptions reflect past experience and are consistent with external sources.

The Rhine FVC s recoverable amount exceeds its carrying amount by $3.6 billion. Based on sensitivity analysis, it is estimated that: (i) if the GIM changes by $1 per barrel, the Rhine FVC s value in use changes by $2.1 billion and, if there was an adverse change in the GIM of $1.70 per barrel, the recoverable amount of the Rhine FVC would equal its carrying amount; (ii) if the volume assumption changes by 13mmbbl a year, the Rhine FVC s value in use changes by $1.2 billion and, if there is an adverse change in refinery volumes of 36mmbbl a year, the recoverable amount of the Rhine FVC would equal its carrying amount; and (iii) a change of 1% in the discount rate would change the Rhine FVC s value in use by $0.8 billion and, if the discount rate increases to 17% the value in use of the Rhine FVC would equal its carrying amount.

US West Coast FVC

Cash flows beyond the three-year period are extrapolated using a 2% growth rate.

The key assumptions to which the calculation of value in use for the West Coast FVC unit is most sensitive are refinery gross margins, refinery production volumes and discount rate. The average value assigned to the refinery gross margin during the plan period is based on a $7.60 per barrel GIM. The average value assigned to the refinery production volume is 170mmbbl a year over the plan period. These key assumptions reflect past experience and are consistent with external sources.

The West Coast FVC s recoverable amount exceeds its carrying amount by $1.6 billion. Based on sensitivity analysis, it is estimated that: (i) if the GIM changes by $1 per barrel, the West Coast FVC s value in use changes by $1.5 billion and, if there was an adverse change in the GIM of $1.10 per barrel, the recoverable amount of the West Coast FVC would equal its carrying amount; (ii) if the volume assumption changes by 8mmbbl a year, the West Coast FVC s value in use changes by $1.1 billion and, if there is an adverse change in refinery volumes of 12mmbbl a year, the recoverable amount of the West Coast FVC would equal its carrying amount; and (iii) a change of 1% in the discount rate would change the West Coast FVC s value in use by $0.6 billion and, if the discount rate increases to 14% the value in use of the West Coast FVC would equal its carrying amount.

Lubricants

Cash flows beyond the three-year period are extrapolated using a 3% growth rate (2007 3%).

For the Lubricants unit, the key assumptions to which the calculation of value in use is most sensitive are operating margin, sales volumes and discount rate. The average values assigned to the operating margin and sales volumes over the plan period are 70 cents per litre (2007 65 cents per litre) and 3.4 billion litres a year (2007 3.3 billion litres a year) respectively. These key assumptions reflect past experience.

The Lubricants unit s recoverable amount exceeds its carrying amount by $5.4 billion. Based on sensitivity analysis, it is estimated that: (i) if there is an adverse change in the operating margin of 14 cents per litre, the recoverable amount of the Lubricants unit would equal its carrying amount; (ii) if the sales volume assumption changes by 200 million litres a year, the Lubricants unit s value in use changes by $1.4 billion and, if there is an adverse change in Lubricants sales volumes of 700 million litres a year, the recoverable amount of the Lubricants unit would equal its carrying amount; and (iii) a change of 1% in the discount rate would change the Lubricants unit s value in use by $1.4 billion and, management believes no reasonably possible change in the discount rate would lead to the Lubricants unit s value in use being equal to its carrying amount.

					$ million
					2008
	Rhine FVC	**US West Coast FVC**	**Lubricants**	**Other**	**Total**
Goodwill	**637**	**1,579**	**3,043**	**203**	**5,462**
Excess of recoverable amount over carrying amount	**3,603**	**1,629**	**5,445**	**n/a**	**n/a**

					$ million
					2007
	Refining	Retail	Lubricants	Other	Total
Goodwill	1,515	827	4,175	109	6,626
Excess of recoverable amount over carrying amount	11,443	4,062	5,028	n/a	n/a

Comparative narrative information is not generally shown because, due to the reorganization of the Refining and Marketing business in 2008, the information is not relevant to an understanding of the current year s financial statements.

Notes on financial statements

13. Distribution and administration expenses

			$ million
	2008	2007	2006
Distribution	**14,075**	14,028	13,174
Administration	**1,337**	1,343	1,273
	15,412	15,371	14,447

14. Currency exchange gains and losses

			$ million
	2008	2007	2006
Currency exchange (gains) losses (credited) charged to income relating to embedded derivatives measured at fair value through profit or loss	**(496)**	12	179
Other currency exchange (gains) losses (credited) charged to income	**156**	(201)	43
	(340)	(189)	222

15. Research and development

			$ million
	2008	2007	2006
Expenditure on research and development	**595**	566	395

16. Operating leases
The table below shows the expense for the year in respect of operating leases. Where an operating lease is entered into solely by the group as the operator of a jointly controlled asset, the total cost is included in this analysis, irrespective of any amounts that have been or will be reimbursed by joint venture partners. Where BP is not the operator of a jointly controlled asset, and has not co-signed the lease, operating lease costs and future minimum lease payments are excluded from the information given below. However, where BP has co-signed the lease, BP s share of the lease costs and future minimum lease payments are included.

			$ million
	2008	2007	2006

Minimum lease payments	**4,870**	4,152	3,647
Contingent rentals	**134**	105	13
Sub-lease rentals	**(201)**	(191)	(131)
	4,803	4,066	3,529

The future minimum lease payments at 31 December, before deducting related rental income from operating sub-leases of $557 million (2007 $618 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

		$ million
Future minimum lease payments	**2008**	2007
Payable within		
1 year	**4,135**	3,780
2 to 5 years	**9,140**	7,660
Thereafter	**5,520**	5,498
	18,795	16,938

Of which, future minimum operating lease commitments relating to drilling rigs are $7,730 million (2007 $5,688 million).

Notes on financial statements

16. Operating leases continued
The following additional disclosures represent the net operating lease expense and net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint venture partners.

Where BP is not the operator of a jointly controlled asset, and has not co-signed the lease, operating lease costs and future minimum lease payments are excluded from the information given below. However, where BP has co-signed the lease, BP s share of the lease costs and future minimum lease payments are included.

			$ million
	2008	2007	2006
Minimum lease payments	**3,693**	3,100	2,924
Contingent rentals	**97**	80	13
Sub-lease rentals	**(197)**	(183)	(131)
	3,593	2,997	2,806

		$ million
Future minimum lease payments	**2008**	2007
Payable within		
1 year	**3,165**	2,826
2 to 5 years	**7,135**	6,519
Thereafter	**4,820**	5,050
	15,120	14,395

Of which, future minimum operating lease commitments relating to drilling rigs are $4,660 million (2007 $3,736 million).

The group enters into operating leases of ships, plant and machinery, commercial vehicles and land and buildings. Typical durations of the leases are as follows:

	Years
Ships	up to 15
Plant and machinery	up to 10
Commercial vehicles	up to 15
Land and buildings	up to 40

The group has entered into a number of structured operating leases for ships and in most cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and spot-charters for ships on standard industry terms.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Exploration and Production segment. In some cases, drilling rig lease rental rates are adjusted periodically to market rates that are influenced by oil prices and may be significantly different from the rates at the inception of the lease. Differences between the rate paid and the rate at inception of the lease are treated as contingent rental expense.

Commercial vehicles hired under operating leases are primarily railcars. Retail service station sites and office accommodation are the main items in the land and buildings category.

The terms and conditions of these operating leases do not impose any significant financial restrictions on the group. Some of the leases of ships and buildings allow for renewals at BP s option.

17. Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Exploration and Production segment.

			$ million
	2008	2007	2006
Exploration and evaluation costs			
Exploration expenditure written off	**385**	347	624
Other exploration costs	**497**	409	421
Exploration expense for the year[a]	**882**	756	1,045
Intangible assets exploration expenditure	**9,031**	5,252	4,110
Net assets	**9,031**	5,252	4,110
Capital expenditure and acquisitions	**4,780**	2,000	1,537
Net cash used in operating activities	**497**	409	421
Net cash used in investing activities	**4,163**	2,000	1,498

[a]In addition to these amounts, an impairment charge of $210 million was recognized in 2008 relating to exploration assets in Vietnam following BP s decision to withdraw from activities in the area concerned.

Notes on financial statements

18. Auditor s remuneration

			$ million
Fees - Ernst & Young	**2008**	2007	2006
Fees payable to the company s auditors for the audit of the company s accounts[a]	**16**	18	15
Fees payable to the company s auditors and its associates for other services			
Audit of the company s subsidiaries pursuant to legislation	**28**	31	31
Other services pursuant to legislation	**13**	14	15
	57	63	61
Tax services	**2**	2	1
Services relating to corporate finance transactions	**2**	1	2
All other services	**5**	8	9
Audit fees in respect of the BP pension plans	**1**	1	
	67	75	73

[a]Fees in respect of the audit of the accounts of BP p.l.c. including the group s consolidated financial statements.
Total fees for 2008 include $3 million of additional fees for 2007 (2007 includes $7 million of additional fees for 2006 and 2006 includes $5 million of additional fees for 2005). Auditor s remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

19. Finance costs

			$ million
	2008	2007	2006
Interest payable	**1,319**	1,433	1,196
Capitalized at 4.00% (2007 5.70% and 2006 5.25%)[a]	**(162)**	(323)	(478)
Unwinding of discount on provisions	**287**	283	245
Unwinding of discount on other payables	**103**		23

	1,547	1,393	986

[a]Tax relief on capitalized interest is $42 million (2007 $81 million and 2006 $182 million).

Revised income statement presentation

With effect from 1 January 2008, the unwinding of the discount on provisions and on other payables is now included within finance costs. Previously, it was included within other finance income or expense. This line item has now been renamed net finance income or expense relating to pensions and other post-retirement benefits. This change does not affect profit before interest and taxation, profit before taxation or profit for the period in the group income statement. For 2007 $283 million was reclassified from other finance income to finance costs (2006 $268 million).

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Notes on financial statements

20. Taxation

Tax on profit

			$ million
	2008	2007	2006
Current tax			
Charge for the year	**13,468**	10,006	11,199
Adjustment in respect of prior years	**(85)**	(171)	442
	13,383	9,835	11,641
Innovene operations			159
Continuing operations	**13,383**	9,835	11,800
Deferred tax			
Origination and reversal of temporary differences in the current year	**(324)**	671	1,956
Adjustment in respect of prior years	**(442)**	(64)	(1,240)
	(766)	607	716
Tax on profit from continuing operations	**12,617**	10,442	12,516

Tax included in the statement of recognized income and expense

			$ million
	2008	2007	2006
Current tax	**(264)**	(178)	(51)
Deferred tax	**(2,492)**	241	985
	(2,756)	63	934
This comprises:			
Currency translation differences	**(100)**	(139)	201
Actuarial gain (loss) relating to pensions and other post-retirement benefits	**(2,602)**	427	820
Share-based payments	**190**	(213)	(26)
Cash flow hedges	**(194)**	(26)	47
Available-for-sale investments	**(50)**	14	(108)
	(2,756)	63	934

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation from continuing operations.

			$ million
	2008	2007	2006
Profit before taxation from continuing operations	**34,283**	31,611	35,142
Tax on profit from continuing operations	**12,617**	10,442	12,516
Effective tax rate	**37%**	33%	36%

			% of profit before taxation from continuing operations
UK statutory corporation tax rate	**28**	30	30
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher rates	**14**	7	11
Tax reported in equity-accounted entities	**(2)**	(2)	(3)
Adjustments in respect of prior years	**(2)**	(1)	(2)
Current year losses unrelieved (prior year losses utilized)	**(1)**	(1)	(1)
Other			1
Effective tax rate	**37**	33	36

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20. Taxation continued
Deferred tax

$ million

			Income statement		Balance sheet
	2008	2007[a]	2006[a]	**2008**	2007[a]
Deferred tax liability					
Depreciation	**1,248**	125	1,423	**23,342**	22,338
Pension plan surpluses	**108**	127	173	**412**	2,136
Other taxable temporary differences	**(2,471)**	1,371	417	**3,626**	5,998
	(1,115)	1,623	2,013	**27,380**	30,472
Deferred tax asset					
Petroleum revenue tax	**121**	139	4	**(192)**	(325)
Pension plan and other post-retirement benefit plan deficits	**104**	(72)	71	**(2,414)**	(1,545)
Decommissioning, environmental and other provisions	**(333)**	(1,069)	(569)	**(4,860)**	(5,107)
Derivative financial instruments	**228**	450	(115)	**(331)**	(541)
Tax credit and loss carry forward	**118**	(466)	220	**(1,821)**	(1,822)
Other deductible temporary differences	**111**	2	(908)	**(1,564)**	(1,917)
	349	(1,016)	(1,297)	**(11,182)**	(11,257)
Net deferred tax (credit) charge and net deferred tax liability	**(766)**	607	716	**16,198**	19,215

[a]A minor amendment has been made to the comparative amounts shown in the analysis of deferred tax by category of temporary difference.

$ million

Analysis of movements during the year	**2008**	2007
At 1 January	**19,215**	18,116
Exchange adjustments	**(67)**	42
Charge (credit) for the year on ordinary activities	**(766)**	607
Charge (credit) for the year in the statement of recognized income and expense	**(2,492)**	241

Acquisitions		199
Other movements	**308**	10
At 31 December	**16,198**	19,215

In 2008, there have been no changes in the statutory tax rates that have materially impacted the group s tax charge. The enactment, in 2007, of a 2% reduction in the rate of UK corporation tax on profits arising from activities outside the North Sea reduced the deferred tax charge by $189 million in that year.

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax assets and unused tax losses can be utilized.

At 31 December 2008, the group had around $6.3 billion (2007 $5.0 billion) of carry-forward tax losses, predominantly in Europe, that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $4.2 billion of losses (2007 $3.2 billion). No deferred tax asset has been recognized in respect of $2.1 billion of losses (2007 $1.8 billion). Substantially all the tax losses have no fixed expiry date.

At 31 December 2008, the group had around $3.4 billion (2007 $4.1 billion) of unused tax credits in the UK and US. A deferred tax asset of $0.5 billion has been recognized in 2008 for these credits (2007 $0.8 billion), which is offset by a deferred tax liability associated with unremitted profits from overseas entities in jurisdictions with a lower tax rate than the UK. No deferred tax asset has been recognized in respect of $2.9 billion of tax credits (2007 $3.2 billion). The UK tax credits do not have a fixed expiry date. The US tax credits, amounting to $1.8 billion, expire ten years after generation, and substantially all expire in the period 2014-2018.

The major components of temporary differences at the end of 2008 are tax depreciation, US inventory holding gains (classified as other taxable temporary differences), provisions, and pension plan and other post-retirement benefit plan deficits.

The group profit and loss account reserve includes $18,347 million (2007 $16,335 million) of earnings retained by subsidiaries and equity-accounted entities.

21. Dividends

	pence per share			cents per share			$ million		
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Dividends announced and paid									
Preference shares							**2**	2	2
Ordinary shares									
March	**6.813**	5.258	5.288	**13.525**	10.325	9.375	**2,553**	2,000	1,922
June	**6.830**	5.151	5.251	**13.525**	10.325	9.375	**2,545**	1,983	1,893
September	**7.039**	5.278	5.324	**14.000**	10.825	9.825	**2,623**	2,065	1,943
December	**8.705**	5.308	5.241	**14.000**	10.825	9.825	**2,619**	2,056	1,926
	29.387	20.995	21.104	**55.050**	42.300	38.400	**10,342**	8,106	7,686
Dividend announced per ordinary share, payable in March 2009	**9.818**			**14.000**			**2,626**		

The group does not account for dividends until they are paid. The accounts for the year ended 31 December 2008 do not reflect the dividend announced on 3 February 2009 and payable in March 2009; this will be treated as an appropriation of profit in the year ended 31 December 2009.

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22. Earnings per ordinary share

			cents per share
	2008	2007	2006
Basic earnings per share	**112.59**	108.76	111.41
Diluted earnings per share	**111.56**	107.84	110.56

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plans (ESOPs) and includes certain shares that will be issuable in the future under employee share plans.

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method. In addition, for 2006 the profit attributable to ordinary shareholders has been adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP and the weighted average number of shares outstanding during the year has been adjusted for the number of shares to be issued for the deferred consideration for the acquisition of our interest in TNK-BP.

			$ million
	2008	2007	2006
Profit from continuing operations attributable to BP shareholders	**21,157**	20,845	22,340
Less dividend requirements on preference shares	**2**	2	2
Profit from continuing operations attributable to BP ordinary shareholders	**21,155**	20,843	22,338
Loss from discontinued operations			(25)
	21,155	20,843	22,313
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP (net of tax)			16
Diluted profit for the year attributable to BP ordinary shareholders	**21,155**	20,843	22,329

			shares thousand
	2008	2007	2006
Basic weighted average number of ordinary shares	**18,789,827**	19,163,389	20,027,527

Potential dilutive effect of ordinary shares issuable under employee share schemes	**172,690**	163,486	109,813
Potential dilutive effect of ordinary shares issuable as consideration for BP s interest in the TNK-BP joint venture			58,118
	18,962,517	19,326,875	20,195,458

The number of ordinary shares outstanding at 31 December 2008, excluding treasury shares and the shares held by the ESOPs, and including certain shares that will be issuable in the future under employee share plans was 18,716,098,258. Between 31 December 2008 and 18 February 2009, the latest practicable date before the completion of these financial statements, there has been an increase of 4,867,626 in the number of ordinary shares outstanding as a result of share issues related to employee share plans. The number of potential ordinary shares issuable through the exercise of options related to employee share plans was 191,340,183 at 31 December 2008. There has been a decrease of 42,722,753 in the number of potential ordinary shares between 31 December 2008 and 18 February 2009.

Loss per share for the discontinued operations in 2006 is derived from the net loss attributable to ordinary shareholders from discontinued operations of $25 million, divided by the weighted average number of ordinary shares for both basic and diluted amounts as shown above.

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23. Property, plant and equipment

$ million

	Land and land improve-ments	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transport-ation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2008	**4,516**	**3,150**	**134,615**	**36,365**	**3,169**	**11,866**	**11,410**	**205,091**
Exchange adjustments	**(320)**	**(287)**	**(1)**	**(1,655)**	**(237)**	**(98)**	**(1,047)**	**(3,645)**
Acquisitions			**136**	**212**				**348**
Additions	**64**	**161**	**12,571**	**4,118**	**530**	**243**	**842**	**18,529**
Transfers[a]			**(454)**	**79**	**(1)**	**454**		**78**
Deletions	**(296)**	**(282)**	**(54)**	**(1,214)**	**(416)**	**(170)**	**(860)**	**(3,292)**
At 31 December 2008	**3,964**	**2,742**	**146,813**	**37,905**	**3,045**	**12,295**	**10,345**	**217,109**
Depreciation								
At 1 January 2008	**718**	**1,533**	**72,486**	**17,417**	**1,820**	**7,126**	**6,002**	**107,102**
Exchange adjustments	**(30)**	**(118)**		**(917)**	**(147)**	**(41)**	**(502)**	**(1,755)**
Charge for the year	**32**	**79**	**7,490**	**1,697**	**313**	**296**	**709**	**10,616**
Impairment losses	**21**	**33**	**469**	**131**	**1**		**19**	**674**
Impairment reversals			**(122)**					**(122)**
Transfers[b]			**(352)**	**4**	**(1)**	**274**		**(75)**
Deletions	**(143)**	**(214)**	**(16)**	**(1,034)**	**(290)**	**(113)**	**(721)**	**(2,531)**
At 31 December 2008	**598**	**1,313**	**79,955**	**17,298**	**1,696**	**7,542**	**5,507**	**113,909**
Net book amount at 31 December 2008	**3,366**	**1,429**	**66,858**	**20,607**	**1,349**	**4,753**	**4,838**	**103,200**
Cost								
At 1 January 2007	4,442	3,129	123,493	32,203	3,006	11,930	11,076	189,279
Exchange adjustments	271	148	22	1,182	73	32	733	2,461
Acquisitions				910				910
Additions	78	171	12,107	3,662	466	181	643	17,308
Transfers			422					422
Reclassified as assets held for sale	(16)			(1,114)				(1,130)
Deletions	(259)	(298)	(1,429)	(478)	(376)	(277)	(1,042)	(4,159)

At 31 December 2007	4,516	3,150	134,615	36,365	3,169	11,866	11,410	205,091
Depreciation								
At 1 January 2007	675	1,470	66,189	16,189	1,762	6,876	5,119	98,280
Exchange adjustments	25	89	19	556	45	16	299	1,049
Charge for the year	52	98	7,370	1,266	341	373	741	10,241
Impairment losses	86	62	189	236	9	14	643	1,239
Impairment reversals			(237)					(237)
Reclassified as assets held for sale	(9)			(486)				(495)
Deletions	(111)	(186)	(1,044)	(344)	(337)	(153)	(800)	(2,975)
At 31 December 2007	718	1,533	72,486	17,417	1,820	7,126	6,002	107,102
Net book amount at 31 December 2007	3,798	1,617	62,129	18,948	1,349	4,740	5,408	97,989
Net book amount at 1 January 2007	3,767	1,659	57,304	16,014	1,244	5,054	5,957	90,999

Assets held under finance leases at net book amount included above								
At 31 December 2008		**12**	**237**	**107**		**8**	**18**	**382**
At 31 December 2007		17	155	185		11	24	392

Decommissioning asset at net book amount included above	Cost	Depreciation	Net
At 31 December 2008	**7,140**	**3,659**	**3,481**
At 31 December 2007	7,851	3,328	4,523

Assets under construction included above	
At 31 December 2008	**17,213**
At 31 December 2007	18,658

[a]Includes $337 million transferred to equity-accounted investments and $415 million transferred from intangible assets.

[b]Includes $75 million transferred to equity-accounted investments.

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24. Goodwill

		$ million
	2008	2007
Cost and net book amount		
At 1 January	**11,006**	10,780
Exchange adjustments	**(1,112)**	126
Acquisitions	**1**	270
Additions	**39**	
Reclassified as assets held for sale		(90)
Deletions	**(56)**	(80)
At 31 December	**9,878**	11,006

25. Intangible assets

						$ million
			2008			2007
	Exploration expenditure	**Other intangibles**	**Total**	Exploration expenditure	Other intangibles	Total
Cost						
At 1 January	**5,637**	**2,898**	**8,535**	4,590	2,396	6,986
Exchange adjustments	**(1)**	**(175)**	**(176)**	3	49	52
Acquisitions	**42**		**42**		35	35
Additions[a]	**4,738**	**354**	**5,092**	2,000	548	2,548
Transfers[b]	**(415)**		**(415)**	(506)		(506)
Deletions	**(576)**	**(150)**	**(726)**	(450)	(130)	(580)
At 31 December	**9,425**	**2,927**	**12,352**	5,637	2,898	8,535
Amortization						
At 1 January	**385**	**1,498**	**1,883**	480	1,260	1,740
Exchange adjustments		**(60)**	**(60)**		25	25
Charge for the year	**385**	**369**	**754**	347	338	685
Impairment losses	**200**		**200**			
Deletions	**(576)**	**(109)**	**(685)**	(442)	(125)	(567)
At 31 December	**394**	**1,698**	**2,092**	385	1,498	1,883
Net book amount at 31 December	**9,031**	**1,229**	**10,260**	5,252	1,400	6,652

Net book amount at 1 January	**5,252**	**1,400**	**6,652**	4,110	1,136	5,246

[a]Included in additions to exploration expenditure in 2008 is $2,331 million in relation to BP s purchase of interests in shale gas assets in the US.
[b]Included in transfers of exploration expenditure in 2007 is $84 million transferred to equity-accounted investments.

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26. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2008 are shown in Note 46. The principal joint venture is the TNK-BP joint venture. Summarized financial information for the group s share of jointly controlled entities is shown below.

									$ million
			2008			2007			2006
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**25,936**	**10,796**	**36,732**	19,463	7,245	26,708	17,863	6,119	23,982
Profit before interest and taxation	**3,588**	**1,343**	**4,931**	3,743	1,299	5,042	4,616	1,218	5,834
Finance costs	**275**	**185**	**460**	264	176	440	192	169	361
Profit before taxation	**3,313**	**1,158**	**4,471**	3,479	1,123	4,602	4,424	1,049	5,473
Taxation	**882**	**397**	**1,279**	993	259	1,252	1,467	260	1,727
Minority interest	**169**		**169**	215		215	193		193
Profit for the year[a]	**2,262**	**761**	**3,023**	2,271	864	3,135	2,764	789	3,553
Non-current assets	**13,874**	**15,584**	**29,458**	12,433	9,841	22,274			
Current assets	**3,760**	**3,687**	**7,447**	6,073	2,642	8,715			
Total assets	**17,634**	**19,271**	**36,905**	18,506	12,483	30,989			
Current liabilities	**3,287**	**1,998**	**5,285**	3,547	1,552	5,099			
Non-current liabilities	**4,820**	**3,973**	**8,793**	5,562	3,620	9,182			
Total liabilities	**8,107**	**5,971**	**14,078**	9,109	5,172	14,281			
Minority interest	**588**		**588**	580		580			
	8,939	**13,300**	**22,239**	8,817	7,311	16,128			
Group investment in jointly controlled entities									
Group share of net assets (as above)	**8,939**	**13,300**	**22,239**	8,817	7,311	16,128			
Loans made by group companies to jointly controlled entities		**1,587**	**1,587**		1,985	1,985			

8,939	**14,887**	**23,826**	8,817	9,296	18,113

[a]BP s share of the profit of TNK-BP in 2006 includes a net gain of $892 million on the disposal of certain assets.

In December 2007, BP signed a memorandum of understanding with Husky Energy Inc. (Husky) to form an integrated North American oil sands business. The transaction was completed on 31 March 2008, with BP contributing its Toledo refinery to a US jointly controlled entity to which Husky contributed $250 million cash and a payable of $2,588 million. In Canada, Husky contributed its Sunrise field to a second jointly controlled entity, with BP contributing $250 million in cash and a payable of $2,264 million. Both jointly controlled entities are owned 50:50 by BP and Husky and are accounted for using the equity method. During the year, equity-accounted earnings from these jointly controlled entities amounted to a loss of $70 million.

BP purchased refined products from the Toledo jointly controlled entity during the year amounting to $3,440 million. In addition, BP purchased crude oil from third parties which it sold to the Toledo jointly controlled entity under an agency agreement. The fees earned by BP for this service, and the total amounts receivable and payable at 31 December 2008 under these arrangements, were not significant. BP will also purchase refinery feedstocks from the Sunrise jointly controlled entity once production commences, which is expected in 2013. During 2008 the unwinding of discount on the payable to the Sunrise jointly controlled entity, included within finance costs in the group income statement, amounted to $103 million.

Our investment in TNK-BP will be reclassified from a jointly controlled entity to an associate with effect from 9 January 2009, the date that BP finalized a revised shareholder agreement with its Russian partners in TNK-BP, Alfa Access-Renova (AAR). The formerly evenly-balanced main board structure is replaced by one with four representatives each from BP and AAR, plus three independent directors. The change in accounting classification from a jointly controlled entity to an associate reflects the ability of the independent directors of TNK-BP to decide on certain matters in the event of disagreement between the shareholder representatives on the board. The group s investment will continue to be accounted for using the equity method.

Transactions between the group and its jointly controlled entities are summarized below.

						$ million
Sales to jointly controlled entities		**2008**		2007		2006
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**2,971**	**1,036**	2,336	888	2,258	830

						$ million
Purchases from jointly controlled entities		**2008**		2007		2006
Product	**Purchases**	**Amount payable at 31 December[a]**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December

Crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**9,115**	**2,547**	2,067	66	3,678	119

[a]Includes $110 million current payable and $2,255 million non-current payable to the Sunrise Oil Sands jointly controlled entity relating to BP s contribution on the establishment of the joint venture.

The terms of the outstanding balances receivable from jointly controlled entities are typically 30 to 45 days, except for a receivable from Ruhr Oel of $386 million, which will be paid over several years as it relates to pension payments. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts.

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27. Investment in associates
The significant associates of the group are shown in Note 46. Summarized financial information for the group s share of associates is set out below.

			$ million
	2008	2007	2006
Sales and other operating revenues	**11,709**	9,855	8,792
Profit before interest and taxation	**1,065**	947	669
Finance costs	**33**	57	63
Profit before taxation	**1,032**	890	606
Taxation	**234**	193	164
Profit for the year	**798**	697	442
Non-current assets	**4,292**	5,012	
Current assets	**1,912**	2,308	
Total assets	**6,204**	7,320	
Current liabilities	**1,669**	1,801	
Non-current liabilities	**1,852**	2,423	
Total liabilities	**3,521**	4,224	
	2,683	3,096	
Group investment in associates			
Group share of net assets (as above)	**2,683**	3,096	
Loans made by group companies to associates	**1,317**	1,483	
	4,000	4,579	

Transactions between the group and its associates are summarized below.

			$ million
Sales to associates	**2008**	2007	2006
	Amount	Amount	Amount

Product	**Sales**	**receivable at 31 December**	Sales	receivable at 31 December	Sales	receivable at 31 December
LNG, crude oil and oil products, natural gas, employee services	**3,248**	**219**	697	60	747	66

$ million

Purchases from associates		**2008**		2007		2006
		Amount payable at 31		Amount payable at 31		Amount payable at 31
Product	**Purchases**	**December**	Purchases	December	Purchases	December
Crude oil, natural gas, transportation tariff	**4,635**	**295**	2,905	574	2,568	236

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts.

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28. Financial instruments and financial risk factors
The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

							$ million
At 31 December							**2008**
	Note	**Loans and receivables**	**Available-for-sale financial assets**	**At fair value through profit and loss**	**Derivative hedging instruments**	**Financial liabilities measured at amortized cost**	**Total carrying amount**
Financial assets							
Other investments listed	**29**		**592**				**592**
Other investments unlisted	**29**		**263**				**263**
Loans		**1,163**					**1,163**
Trade and other receivables	**31**	**29,489**					**29,489**
Derivative financial instruments	**34**			**12,501**	**1,063**		**13,564**
Cash at bank and in hand	**32**	**4,001**					**4,001**
Cash equivalents listed	**32**		**4,060**				**4,060**
Cash equivalents unlisted	**32**		**136**				**136**
Financial liabilities							
Trade and other payables	**33**					**(33,140)**	**(33,140)**
Derivative financial instruments	**34**			**(13,173)**	**(2,075)**		**(15,248)**
Accruals						**(7,527)**	**(7,527)**
Finance debt	**35**					**(33,204)**	**(33,204)**
		34,653	**5,051**	**(672)**	**(1,012)**	**(73,871)**	**(35,851)**

						$ million
At 31 December						2007
	Loans and	Available-for-sale financial	At fair value through profit	Derivative hedging	Financial liabilities measured at	Total carrying

	Note	receivables	assets	and loss	instruments	amortized cost	amount
Financial assets							
Other investments listed	29		1,617				1,617
Other investments unlisted	29		213				213
Loans		1,164					1,164
Trade and other receivables	31	38,710					38,710
Derivative financial instruments	34			9,155	907		10,062
Cash at bank and in hand	32	2,996					2,996
Cash equivalents listed	32		3				3
Cash equivalents unlisted	32		563				563
Financial liabilities							
Trade and other payables	33					(40,062)	(40,062)
Derivative financial instruments	34			(11,284)	(123)		(11,407)
Accruals						(7,599)	(7,599)
Finance debt	35					(31,045)	(31,045)
		42,870	2,396	(2,129)	784	(78,706)	(34,785)

The fair value of finance debt is shown in Note 35. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including market risks relating to commodity prices, foreign currency exchange rates, interest rates and equity prices, credit risk and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group s financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

Notes on financial statements

28. Financial instruments and financial risk factors continued

The group s trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while activities in the financial markets are managed by the treasury function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk associated with trading activity. These processes meet generally accepted industry practice and reflect the principles of the Group of Thirty Global Derivatives Study recommendations. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a separate control framework as described more fully below.

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The market price movements that the group is exposed to include oil, natural gas and power prices (commodity price risk), foreign currency exchange rates, interest rates, equity prices and other indices that could adversely affect the value of the group s financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with this control framework the group enters into various transactions using derivatives for risk management purposes.

During recent periods of increased volatility in financial markets the group s policies in relation to managing market risk continue to be appropriate and are outlined in further detail below. The group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing and tail risk analysis.

The trading value-at-risk model is used for derivative financial instrument types such as: interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price forwards, futures, swap agreements and options. Additionally, where physical commodities or non-derivative forward contracts are held as part of a trading position, they are also reflected in the value-at-risk model. For options, a linear approximation is included in the value-at-risk models when full revaluation is not possible.

The value-at-risk table does not incorporate any of the group s natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table. Instead separate sensitivity analyses are disclosed below.

Value-at-risk limits are in place for each trading activity and for the group s trading activity in total. The board has delegated an overall limit of $100 million value at risk in support of this trading activity. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				**2008**				2007
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**76**	**20**	**37**	**69**	50	24	35	38
Oil price trading	**69**	**12**	**25**	**63**	46	16	26	34
Natural gas price trading	**50**	**12**	**24**	**23**	32	9	16	15
Power price trading	**14**	**3**	**7**	**4**	6	1	3	5
Currency trading	**4**		**2**		6	1	3	2
Interest rate trading	**7**		**2**	**1**	11		5	2
Other trading	**5**	**1**	**2**	**2**	7		2	1

(i) Commodity price risk

The group s integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes available in the related commodity markets. Natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories. Trading value-at-risk information in relation to these activities is shown in the table above.

Notes on financial statements

28. Financial instruments and financial risk factors continued
As described above, the group also carries out risk management of certain short-term natural business exposures using over-the-counter swaps and exchange futures contracts with a duration of less than three years. In past periods commodity price risk relating to this activity has been managed using value-at-risk measures. For 2008 a separate control framework is now used as described under market risk above. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $90 million at 31 December 2008. This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to largely offset the gain or loss on the derivatives.

In addition, the group has embedded derivatives relating to certain natural gas and crude oil contracts. The net fair value of these embedded derivatives was a liability of $1,867 million at 31 December 2008 (2007 liability of $2,085 million). Key information on the natural gas contracts is given below.

At 31 December	**2008**	2007
Remaining contract terms	**1 year 9 months to 9 years 9 months**	9 months to 11 years
Contractual/notional amount	**3,585 million therms**	3,889 million therms
Discount rate nominal risk free	**2.5%**	4.5%

For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or unfavourable change in the key assumptions is as follows.

$ million

At 31 December	**2008**				2007			
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**291**	**81**	**27**	**16**	317	72	37	31
Unfavourable 10% change	**(289)**	**(81)**	**(27)**	**(16)**	(368)	(84)	(34)	(32)

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(ii) Foreign currency exchange risk

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above. This activity is described as currency trading in the value-at-risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects on the group s reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group s reported results. The main underlying economic currency of the group s cash flows is the US dollar. This is because BP s major product, oil, is priced internationally in US dollars. BP s foreign currency exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then dealing with any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and managing such risk to keep the 12-month foreign currency value at risk below $200 million. At 31 December 2008, the foreign currency value at risk was $70 million (2007 $60 million). At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 34.

For highly probable forecast capital expenditures the group locks in the US-dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, euro, Norwegian krone, Australian dollar, Korean won and Canadian dollar, and at 31 December 2008 open contracts were in place for $949 million sterling, $553 million euro, $392 million Norwegian krone, $303 million Australian dollar, $187 million Korean won and $712 million Canadian dollar capital expenditures maturing within seven years, with over 65% of the deals maturing within two years (2007 $732 million sterling, $931 million euro, $479 million Norwegian krone, $38 million Australian dollar, $243 million Korean won and $7 million Canadian dollar capital expenditures maturing within eight years with over 80% of the deals maturing within two years).

For other UK, European, Canadian and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2008, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $1,660 million (2007 $2,800 million); receive euro, pay US dollar cylinders for $1,612 million (2007 $1,400 million); receive Canadian dollar, pay US dollar cylinders for $250 million (2007 nil); and receive Australian dollar, pay US dollar cylinders for $455 million (2007 $382 million).

At 31 December 2008, the open positions relating to currency forwards consisted of buy sterling, sell US dollar, currency forwards for $816 million (2007 nil); buy euro, sell US dollar currency forwards for $141 million (2007 nil); buy Canadian dollar, sell US dollar, currency forwards for $50 million (2007 nil); and buy Australian dollar, sell US dollar, currency forwards for $90 million (2007 nil).

In addition, most of the group s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2008, the total foreign currency net borrowings not swapped into US dollars amounted to $1,037 million (2007 $1,045 million). Of this total, $92 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2007 $268 million, being $191 million in Canadian dollars and $77 million in Trinidad & Tobago dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $9 million (2007 $27 million).

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28. Financial instruments and financial risk factors continued

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above. This activity is described as interest rate trading in the value-at-risk table above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt.

While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a US dollar floating rate exposure but in certain defined circumstances maintains a fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2008 was 72% of total finance debt outstanding (2007 68%). The weighted average interest rate on finance debt at 31 December 2008 is 3% (2007 5%) and the weighted average maturity of fixed rate debt is three years (2007 two years).

The group s earnings are sensitive to changes in interest rates on the floating rate element of the group s finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2009, it is estimated that the group s profit before taxation for 2009 would decrease by approximately $239 million (2007 $168 million decrease in 2008). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2008 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

(iv) Equity price risk

The group holds equity investments, typically made for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized directly in equity. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. Impairment losses of $546 million have been recognized in 2008 relating to listed non-current available-for-sale investments. For further information see Note 29.

At 31 December 2008, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to equity of $59 million (2007 $162 million credit to equity), whilst a decrease of 10% in quoted equity prices would result in an immediate charge to profit or loss of $48 million and a charge to equity of $11 million (2007 $162 million charge to equity).

At 31 December 2008, 56% (2007 70%) of the carrying amount of non-current available-for-sale financial assets represented the group s stake in Rosneft, thus the group s exposure is concentrated on changes in the share price of this equity in particular.

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables.

The group has a credit policy, approved by the CFO, that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy are formal delegated authorities to the sales and marketing teams to incur credit risk and to a specialized credit function to set counterparty limits; the establishment of credit systems and processes to ensure that counterparties are rated and limits set; and systems to monitor exposure against limits and report regularly on those exposures, and immediately on any excesses, and to track and report credit losses. The treasury function provides a similar credit risk management activity with respect to group-wide exposures to banks and other financial institutions.

In the current economic environment the group has placed increased emphasis on the management of credit risk. Policies and processes have been reviewed during the year and credit exposures with banks and others have been reduced through netting and collateral arrangements, or reduced activity where appropriate.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty s business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to the group by the counterparty, together with external credit ratings, if any, including ratings prepared by Moody s Investor Service and Standard & Poor s. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained. Once assigned a credit rating, each counterparty is allocated a maximum exposure limit.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits or letters of credit and parent company guarantees. Trade and other derivative assets and liabilities are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. At 31 December 2008, the maximum credit exposure was $52,413 million (2007 $53,498 million). Collateral received and recognized in the balance sheet at the year-end was $1,121 million (2007 $39 million) and collateral held off balance sheet was $203 million (2007 $474 million). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2008 were $223 million (2007 $443 million) in respect of liabilities of jointly controlled entities and associates and $613 million (2007 $601 million) in respect of liabilities of other third parties.

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28. Financial instruments and financial risk factors continued

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group s principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

Reports are regularly prepared and presented to the GFRC that cover the group s overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

It is estimated that over 80% (2007 80%) of the counterparties to the contracts comprising the derivative financial instruments in an asset position are of investment grade credit quality.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 60-65% (2007 65-70%) of the trade receivables portfolio exposure are of investment grade quality. With respect to the trade and other receivables that are neither impaired nor past due, there are no indications as of the reporting date that the debtors will not meet their payment obligations.

The group does not typically renegotiate the terms of trade receivables; however, if a renegotiation does take place, the outstanding balance is included in the analysis based on the original payment terms. There were no significant renegotiated balances outstanding at 31 December 2008 or 31 December 2007.

		$ million
Trade and other receivables at 31 December	**2008**	2007
Neither impaired nor past due	**25,838**	35,167
Impaired (net of valuation allowance)	**73**	145
Not impaired and past due in the following periods		
within 30 days	**1,323**	2,350
31 to 60 days	**489**	273
61 to 90 days	**596**	311
over 90 days	**1,170**	464
	29,489	38,710

The movement in the valuation allowance for trade receivables is set out below.

		$ million
	2008	2007
At 1 January	**406**	421
Exchange adjustments	**(32)**	34
Charge for the year	**191**	175
Utilization	**(174)**	(224)

At 31 December	**391**	406

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group s business activities may not be available. The group s liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group s overall net currency positions.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group s treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable borrowing requirements. At 31 December 2008, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,950 million, of which $4,550 million are in place until at least the fourth quarter of 2011 (2007 $4,950 million, of which $4,550 million are in place until at least the fourth quarter of 2011). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise $20 billion of debt for maturities of one month or longer. At 31 December 2008, the amount drawn down against the DIP was $10,334 million (2007 $10,438 million). In addition, the group has in place a US Shelf Registration under which it may raise $10 billion of debt with maturities of one month or longer. At 31 December 2008, the amount drawn down under the US Shelf was $6,500 million (2007 $2,500 million).

The group has long-term debt ratings of Aa1 (stable outlook) and AA (stable outlook), (2007 Aa1 (stable outlook) and AA+ (negative outlook)) assigned respectively by Moody s and Standard and Poor s.

Despite current uncertainty in the financial market including a lack of liquidity for some borrowers, we have been able to issue $5 billion of long-term debt in the fourth quarter of 2008. In addition, we have been able to issue short-term commercial paper at competitive rates. In the context of unforeseen market volatility, we have however, increased the cash and cash equivalents held by the group to $8.2 billion at the end of 2008 compared with $3.6 billion at the end of 2007.

The amounts shown for finance debt in the table below include expected interest payments on borrowings and the future minimum lease payments with respect to finance leases.

Notes on financial statements

28. Financial instruments and financial risk factors continued
There are amounts included within finance debt that we show in the table below as due within one year to reflect the earliest contractual repayment dates but that are expected to be repaid over the maximum long-term maturity profiles of the contracts as described in Note 35. US Industrial Revenue/Municipal Bonds of $3,166 million (2007 $2,880 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 40 years (2007 1 to 35 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,806 million (2007 $1,899 million) that mature within nine years.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

			$ million			
At 31 December			**2008**			2007
	Trade and other payables	**Accruals**	**Finance debt**	Trade and other payables	Accruals	Finance debt
Within one year	**30,598**	**6,743**	**16,670**	39,576	6,640	16,561
1 to 2 years	**402**	**359**	**5,934**	147	351	8,011
2 to 3 years	**898**	**77**	**3,419**	62	245	3,515
3 to 4 years	**902**	**72**	**2,647**	26	78	1,447
4 to 5 years	**223**	**67**	**5,072**	30	49	2,352
5 to 10 years	**53**	**164**	**1,316**	197	200	1,100
Over 10 years	**64**	**45**	**1,050**	24	36	1,447
	33,140	**7,527**	**36,108**	40,062	7,599	34,433

The group manages liquidity risk associated with derivative contracts on a portfolio basis, considering both physical commodity sale and purchase contracts together with financially-settled derivative assets and liabilities.

The held-for-trading derivatives amounts in the table below represent the total contractual cash outflows by period for the purchases of physical commodities under derivative contracts and the estimated cash outflows of financially-settled derivative liabilities. The group also holds derivative contracts for the sale of physical commodities and financially-settled derivative assets that are expected to generate cash inflows that will be available to the group to meet cash outflows on purchases and liabilities. These contracts are excluded from the table below. The amounts disclosed for embedded derivatives represent the contractual cash outflows of purchase contracts some of which have embedded derivatives associated with them which are financial assets.

		$ million
At 31 December	**2008**	2007

	Embedded derivatives	**Held-for-trading derivatives**	Embedded derivatives	Held-for-trading derivatives
Within one year	**562**	**60,270**	699	82,465
1 to 2 years	**403**	**8,189**	659	8,541
2 to 3 years	**470**	**2,437**	641	2,906
3 to 4 years	**509**	**1,111**	627	707
4 to 5 years	**535**	**841**	624	338
5 to 10 years	**1,538**	**2,087**	2,342	592
Over 10 years		**553**		447
	4,017	**75,488**	5,592	95,996

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and the gross settlement amount where the pay leg of a derivative will be settled separately to the receive leg, as in the case of cross-currency interest rate swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement day risk exposure is considered to be negligible.

		$ million
At 31 December	**2008**	2007
Within one year	**3,426**	1,708
1 to 2 years	**3,024**	1,220
2 to 3 years	**1,037**	3,759
3 to 4 years	**1,731**	365
4 to 5 years	**1,389**	1,650
5 to 10 years	**129**	105
	10,736	8,807

Notes on financial statements

29. Other investments

		$ million
	2008	2007
Listed	**592**	1,617
Unlisted	**263**	213
	855	1,830

Other investments comprise equity investments that have no fixed maturity date or coupon rate. These investments are classified as available-for-sale financial assets and as such are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded directly in equity. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant investment is the group s stake in Rosneft which had a fair value of $483 million at 31 December 2008 (2007 $1,285 million). During 2008, an impairment loss of $517 million was recognized relating to the Rosneft investment (see Note 11), $29 million relating to other listed investments and $17 million relating to unlisted investments (2007 $80 million relating to unlisted investments).

30. Inventories

		$ million
	2008	2007
Crude oil	**4,396**	8,157
Natural gas	**107**	160
Refined petroleum and petrochemical products	**9,318**	14,723
	13,821	23,040
Supplies	**1,588**	1,517
	15,409	24,557
Trading inventories	**1,412**	1,997
	16,821	26,554
Cost of inventories expensed in the income statement	**266,982**	200,766

The inventory valuation at 31 December 2008 is stated net of a provision of $1,412 million (2007 $117 million) to write inventories down to their net realizable value. The net movement in the provision during the year was a charge of $1,295 million (2007 $86 million credit).

31. Trade and other receivables

				$ million
		2008		2007
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**22,869**		33,012	
Amounts receivable from jointly controlled entities	**1,035**		888	
Amounts receivable from associates	**219**		380	
Other receivables	**4,656**	**710**	3,462	968
	28,779	**710**	37,742	968
Non-financial assets				
Other receivables	**482**		278	
	29,261	**710**	38,020	968

Trade and other receivables are predominantly non-interest bearing.

Notes on financial statements

32. Cash and cash equivalents

		$ million
	2008	2007
Cash at bank and in hand	**4,001**	2,996
Cash equivalents		
Listed	**4,060**	3
Unlisted	**136**	563
	8,197	3,562

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; and short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

Cash and cash equivalents at 31 December 2008 includes $2,133 million (2007 $1,294 million) that is restricted. This relates principally to amounts on deposit to cover initial margins on trading exchanges.

33. Trade and other payables

				$ million
		2008		2007
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**20,129**		30,735	
Amounts payable to jointly controlled entities	**292**	**2,255**	66	
Amounts payable to associates	**295**		650	
Other payables	**9,882**	**287**	8,125	486
	30,598	**2,542**	39,576	486
Non-financial liabilities				
Production and similar taxes	**445**	**538**	803	765
Other payables	**2,601**		2,773	
	3,046	**538**	3,576	765
	33,644	**3,080**	43,152	1,251

Trade and other payables are predominantly interest free.

Notes on financial statements

34. Derivative financial instruments
An outline of the group s financial risks and the objectives and policies pursued in relation to those risks is set out in Note 28.

IAS 39 prescribes strict criteria for hedge accounting, whether as a cash flow or fair value hedge or a hedge of a net investment in a foreign operation, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in profit or loss.

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

The fair values of derivative financial instruments at 31 December are set out below.

				$ million
		2008		2007
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**278**	**(273)**	147	(317)
Oil price derivatives	**3,813**	**(3,523)**	3,214	(3,432)
Natural gas price derivatives	**6,945**	**(6,113)**	4,388	(4,022)
Power price derivatives	**978**	**(904)**	1,121	(1,140)
Other derivatives	**90**	**(96)**	30	
	12,104	**(10,909)**	8,900	(8,911)
Embedded derivatives				
Commodity contracts	**397**	**(2,264)**	255	(2,340)
Interest rate contracts				(33)
	397	**(2,264)**	255	(2,373)
Cash flow hedges				
Currency forwards, futures and cylinders	**120**	**(1,175)**	226	(45)
Cross-currency interest rate swaps	**109**	**(558)**	122	(52)
	229	**(1,733)**	348	(97)
Fair value hedges				
Cross-currency interest rate swaps	**465**	**(342)**	430	(9)
Interest rate swaps	**367**		89	(17)
	832	**(342)**	519	(26)

Hedges of net investments in foreign operations	**2**		40	
	13,564	**(15,248)**	10,062	(11,407)
Of which current	**8,510**	**(8,977)**	6,321	(6,405)
non-current	**5,054**	**(6,271)**	3,741	(5,002)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 28.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

Changes during the year in the net fair value of derivatives held for trading purposes were as follows.

$ million

	Currency	**Oil price**	**Natural gas price**	**Power price**	**Other**	**Total**
Fair value of contracts at 1 January 2008	**(170)**	**(218)**	**366**	**(19)**	**30**	**(11)**
Contracts realized or settled in the year	**24**	**190**	**(216)**	**3**	**(15)**	**(14)**
Fair value of options at inception		**(216)**	**(201)**	**34**		**(383)**
Fair value of other new contracts entered into during the year		**66**	**49**			**115**
Changes in fair values relating to price	**151**	**468**	**881**	**60**	**(21)**	**1,539**
Exchange adjustments			**(47)**	**(4)**		**(51)**
Fair value of contracts at 31 December 2008	**5**	**290**	**832**	**74**	**(6)**	**1,195**

Notes on financial statements

34. Derivative financial instruments continued

						$ million
	Currency	Oil price	Natural gas price	Power price	Other	Total
Fair value of contracts at 1 January 2007	105	296	855	42	113	1,411
Contracts realized or settled in the year	(109)	(289)	(602)	(68)	(83)	(1,151)
Fair value of options at inception		28	168	36		232
Fair value of other new contracts entered into during the year			1			1
Changes in fair values relating to price	(167)	(253)	(58)	(20)		(498)
Exchange adjustments	1		2	(9)		(6)
Fair value of contracts at 31 December 2007	(170)	(218)	366	(19)	30	(11)

If at inception of a contract the valuation cannot be supported by observable market data, any gain determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as day-one profit . This deferred gain is recognized in the income statement over the life of the contract until substantially all of the remaining contract term can be valued using observable market data at which point any remaining deferred gain is recognized in income. Changes in valuation from this initial valuation are recognized immediately through income.

The following table shows the changes in the day-one profits deferred on the balance sheet.

				$ million
		2008		2007
	Oil price	**Natural gas price**	Oil price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January		**36**		36
Fair value of new contracts at inception not recognized in the income statement	**66**	**49**		1
Fair value recognized in the income statement	**(34)**	**(2)**		(1)
Fair value of contracts not recognized through profit at 31 December	**32**	**83**		36

Derivative assets held for trading have the following fair values and maturities.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**53**	**90**	**67**	**37**	**20**	**11**	**278**
Oil price derivatives	**3,368**	**353**	**61**	**11**	**11**	**9**	**3,813**
Natural gas price derivatives	**3,940**	**1,090**	**545**	**436**	**271**	**663**	**6,945**
Power price derivatives	**688**	**256**	**31**	**1**	**2**		**978**
Other derivatives	**90**						**90**
	8,139	**1,789**	**704**	**485**	**304**	**683**	**12,104**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	123	10	6	5	1	2	147
Oil price derivatives	2,545	471	113	39	26	20	3,214
Natural gas price derivatives	2,170	677	333	283	216	709	4,388
Power price derivatives	819	250	52				1,121
Other derivatives	12	18					30
	5,669	1,426	504	327	243	731	8,900

Derivative liabilities held for trading have the following fair values and maturities.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(257)**		**(2)**	**(1)**	**(13)**		**(273)**

Oil price derivatives	**(3,001)**	**(458)**	**(36)**	**(18)**	**(9)**	**(1)**	**(3,523)**
Natural gas price derivatives	**(3,484)**	**(987)**	**(438)**	**(310)**	**(283)**	**(611)**	**(6,113)**
Power price derivatives	**(722)**	**(159)**	**(18)**	**(4)**	**(1)**		**(904)**
Other derivatives	**(95)**	**(1)**					**(96)**
	(7,559)	**(1,605)**	**(494)**	**(333)**	**(306)**	**(612)**	**(10,909)**

Notes on financial statements

34. Derivative financial instruments continued

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(145)	(99)	(32)	(16)	(15)	(10)	(317)
Oil price derivatives	(2,735)	(512)	(135)	(25)	(22)	(3)	(3,432)
Natural gas price derivatives	(2,089)	(527)	(298)	(219)	(185)	(704)	(4,022)
Power price derivatives	(832)	(246)	(61)	(1)			(1,140)
	(5,801)	(1,384)	(526)	(261)	(222)	(717)	(8,911)

The following table shows the fair value of derivative assets held for trading, analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**40**	**43**	**30**	**7**	**6**	**2**	**128**
Prices sourced from observable data or market corroboration	**7,628**	**1,614**	**553**	**361**	**190**	**56**	**10,402**
Prices based on models and other valuation methods	**471**	**132**	**121**	**117**	**108**	**625**	**1,574**
	8,139	**1,789**	**704**	**485**	**304**	**683**	**12,104**

$ million

2007

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	169	53	49	3		2	276
Prices sourced from observable data or market corroboration	5,417	1,174	363	225	140		7,319
Prices based on models and other valuation methods	83	199	92	99	103	729	1,305
	5,669	1,426	504	327	243	731	8,900

The following table shows the fair value of derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation.

$ million

2008

	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted	**(227)**		**(2)**		**(13)**		**(242)**
Prices sourced from observable data or market corroboration	**(6,997)**	**(1,482)**	**(365)**	**(209)**	**(182)**	**(27)**	**(9,262)**
Prices based on models and other valuation methods	**(335)**	**(123)**	**(127)**	**(124)**	**(111)**	**(585)**	**(1,405)**
	(7,559)	**(1,605)**	**(494)**	**(333)**	**(306)**	**(612)**	**(10,909)**

$ million

2007

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted	(50)	(50)		(1)	(9)	(1)	(111)
Prices sourced from observable data or market corroboration	(5,629)	(1,116)	(420)	(143)	(103)		(7,411)
Prices based on models and other valuation methods	(122)	(218)	(106)	(117)	(110)	(716)	(1,389)

	(5,801)	(1,384)	(526)	(261)	(222)	(717)	(8,911)

Prices actively quoted refers to the fair value of contracts valued solely using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data, for example, swaps and physical forward contracts. Prices based on models and other valuation methods refers to the fair value of a contract valued in part using internal models due to the absence of quoted prices, including over-the-counter options. The net change in fair value of contracts based on models and other valuation methods during the year was a gain of $253 million (2007 $94 million loss and 2006 $117 million loss).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all of these items was a gain of $6,721 million (2007 $376 million gain and 2006 $2,842 million gain).

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34. Derivative financial instruments continued

Embedded derivatives

Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

All the embedded derivatives are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, these are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships.

The following table shows the changes during the year in the net fair value of embedded derivatives.

						$ million
			2008			2007
	Commodity price	**Interest rate**	**Total**	Commodity price	Interest rate	Total
Fair value of contracts at 1 January	**(2,085)**	**(33)**	**(2,118)**	(2,064)	(26)	(2,090)
Contracts realized or settled in the year	**294**	**38**	**332**	449		449
Changes in valuation techniques or key assumptions				130		130
Changes in fair values relating to price	**(928)**	**(5)**	**(933)**	(567)	(7)	(574)
Exchange adjustments	**852**		**852**	(33)		(33)
Fair value of contracts at 31 December	**(1,867)**		**(1,867)**	(2,085)	(33)	(2,118)

Embedded derivative assets have the following fair values and maturities.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Commodity price embedded derivatives	**50**	**116**	**75**	**45**	**36**	**75**	**397**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	193	18	15	7	10	12	255

Embedded derivative liabilities have the following fair values and maturities.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Commodity price embedded derivatives	**(404)**	**(322)**	**(365)**	**(303)**	**(271)**	**(599)**	**(2,264)**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Commodity price embedded derivatives	(554)	(437)	(299)	(244)	(219)	(587)	(2,340)
Interest rate embedded derivatives	(33)						(33)
	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)

Notes on financial statements

34. Derivative financial instruments continued
Embedded derivative assets have the following fair values when analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted							
Prices sourced from observable data or market corroboration	**35**						**35**
Prices based on models and other valuation methods	**15**	**116**	**75**	**45**	**36**	**75**	**362**
	50	**116**	**75**	**45**	**36**	**75**	**397**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted							
Prices sourced from observable data or market corroboration	61						61
Prices based on models and other valuation methods	132	18	15	7	10	12	194
	193	18	15	7	10	12	255

Embedded derivative liabilities have the following fair values when analysed by maturity period and by methodology of fair value estimation.

							$ million
							2008
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Prices actively quoted							
Prices sourced from observable data or market corroboration	**(10)**						**(10)**
Prices based on models and other valuation methods	**(394)**	**(322)**	**(365)**	**(303)**	**(271)**	**(599)**	**(2,254)**
	(404)	**(322)**	**(365)**	**(303)**	**(271)**	**(599)**	**(2,264)**

							$ million
							2007
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Prices actively quoted							
Prices sourced from observable data or market corroboration							
Prices based on models and other valuation methods	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)
	(587)	(437)	(299)	(244)	(219)	(587)	(2,373)

The net change in fair value of contracts based on models and other valuation methods during the year is a gain of $287 million (2007 gain of $18 million and 2006 gain of $423 million).

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2008	2007	2006
Commodity price embedded derivatives	**(106)**		604
Interest rate embedded derivatives	**(5)**	(7)	4
Fair value (loss) gain	**(111)**	(7)	608

The fair value gain (loss) in the above table includes $496 million of exchange gains (2007 $12 million of exchange losses and 2006 $179 million of exchange losses) arising on contracts that are denominated in a currency other than the functional currency of the individual operating unit.

Notes on financial statements

34. Derivative financial instruments continued

Cash flow hedges

At 31 December 2008, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions, as well as cross-currency interest rate swaps to fix the US dollar interest rate and US dollar redemption value, with matching critical terms on the currency leg of the swap with the underlying non-US dollar debt issuance. Note 28 outlines the management of risk aspects for currency and interest rate risk. For cash flow hedges the group only claims for the intrinsic value on the currency with any fair value attributable to time value taken immediately to profit or loss. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a loss of $45 million (2007 gain of $74 million and 2006 gain of $93 million). Of this, a loss of $1 million is included in production and manufacturing expenses (2007 $143 million gain and 2006 $162 million gain) and a loss of $44 million is included in finance costs (2007 $69 million loss and 2006 $69 million loss). The amount removed from equity during the year and included in the carrying amount of non-financial assets was a gain of $38 million (2007 $40 million gain and 2006 $6 million gain).

The amounts retained in equity at 31 December 2008 are expected to mature and affect the income statement by a $826 million loss in 2009, a loss of $92 million in 2010 and a loss of $182 million in 2011 and beyond.

Fair value hedges

At 31 December 2008, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The gain on the hedging derivative instruments taken to the income statement in 2008 was $2 million (2007 $334 million gain and 2006 $257 million gain) offset by a loss on the fair value of the finance debt of $20 million (2007 $327 million loss and 2006 $257 million loss).

The interest rate and cross-currency interest rate swaps have an average maturity of three to four years, (2007 one to two years) and are used to convert sterling, euro, Swiss franc and Australian dollar denominated borrowings into US dollar floating rate debt. Note 28 outlines the group s approach to interest rate risk management.

Hedges of net investments in foreign operations

The group holds currency swap contracts as a hedge of a long-term investment in a UK subsidiary expiring in 2009. At 31 December 2008, the hedge had a fair value of $2 million (2007 $40 million) and the loss on the hedge recognized in equity in 2008 was $38 million (2007 $67 million loss and 2006 $105 million gain). US dollars have been sold forward for sterling purchased and match the underlying liability with no significant ineffectiveness reflected in the income statement.

35. Finance debt

						$ million
			2008			2007
	Within 1 year[a]	**After 1 year**	**Total**	Within 1 year [a]	After 1 year	Total
Borrowings	**15,647**	**16,937**	**32,584**	15,149	15,004	30,153
Net obligations under finance leases	**93**	**527**	**620**	245	647	892
	15,740	**17,464**	**33,204**	15,394	15,651	31,045

[a]Amounts due within one year include current maturities of long-term debt and borrowings that are expected to be repaid later than the earliest contractual repayment dates of within one year. US Industrial Revenue/Municipal Bonds of $3,166 million (2007 $2,880 million) with earliest contractual repayment dates within one year have expected repayment dates ranging from 1 to 40 years (2007 1 to 35 years). The bondholders typically have the option to tender these bonds for repayment on interest reset dates; however, any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when internally assessing the maturity profile of its finance debt. Similar treatment is applied for loans associated with long-term gas supply contracts totalling $1,806 million (2007 $1,899 million) that mature within nine years.

Notes on financial statements

35. Finance debt continued
The following table shows, by major currency, the group s finance debt at 31 December and the weighted average interest rates achieved at those dates through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

			Fixed rate debt			Floating rate debt
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Total
	%	Years	$ million	%	$ million	$ million
						2008
US dollar	**5**	**3**	**9,005**	**2**	**22,116**	**31,121**
Sterling				**6**	**21**	**21**
Euro	**4**	**3**	**74**	**4**	**1,330**	**1,404**
Other currencies	**7**	**10**	**216**	**7**	**442**	**658**
			9,295		**23,909**	**33,204**
						2007
US dollar	5	2	9,541	5	20,460	30,001
Sterling				6	35	35
Euro	4	4	81	5	107	188
Other currencies	7	13	268	7	553	821
			9,890		21,155	31,045

Finance leases
The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. Future minimum lease payments under finance leases are set out below.

		$ million
	2008	2007

Future minimum lease payments payable within		
1 year	**116**	268
2 to 5 years	**361**	393
Thereafter	**439**	630
	916	1,291
Less finance charges	**296**	399
Net obligations	**620**	892
Of which payable within 1 year	**93**	245
payable within 2 to 5 years	**234**	217
payable thereafter	**293**	430

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the year from 31 December 2008, whereas in the balance sheet the amount would be reported within current liabilities.

The carrying amount of the group s short-term borrowings, comprising mainly commercial paper, bank loans, overdrafts and US Industrial Revenue/Municipal Bonds, approximates their fair value. The fair value of the group s long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group s current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2008		2007
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**9,913**	**9,913**	11,212	11,212
Long-term borrowings	**23,239**	**22,671**	19,094	18,941
Net obligations under finance leases	**638**	**620**	908	892
Total finance debt	**33,790**	**33,204**	31,214	31,045

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36. Capital disclosures and analysis of changes in net debt

The group defines capital as the total equity of the group. The group s objective for managing capital is to deliver competitive, secure and sustainable returns to maximize long-term shareholder value. BP is not subject to any externally-imposed capital requirements.

The group s approach to managing capital is set out in its financial framework. The group aims to balance returns to shareholders between long-term growth and current returns via the dividend whilst maintaining capital discipline in relation to investing activities and taking action on costs to respond to the current environment. At the beginning of 2008, the group rebalanced returns to shareholders by increasing the dividend component. As a result, the share buyback programme was curtailed and then suspended in September in light of the uncertain environment.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP uses these measures to provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . All components of equity are included in the denominator of the calculation. We believe that a net debt ratio in the range 20-30% provides an efficient capital structure and an appropriate level of financial flexibility.

At 31 December 2008 the net debt ratio was 21% (2007 22%).

		$ million
At 31 December	**2008**	2007
Gross debt	**33,204**	31,045
Less: Cash and cash equivalents	**8,197**	3,562
Less: Fair value (liability) asset of hedges related to finance debt	**(34)**	666
Net debt	**25,041**	26,817
Equity	**92,109**	94,652
Net debt ratio	**21%**	22%

An analysis of changes in net debt is provided below.

						$ million
			2008			2007
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(30,379)**	**3,562**	**(26,817)**	(23,712)	2,590	(21,122)

Exchange adjustments	**102**	**(184)**	**(82)**	(122)	135	13
Net cash flow	**(2,825)**	**4,819**	**1,994**	(6,411)	837	(5,574)
Other movements	**(136)**		**(136)**	(134)		(134)
At 31 December	**(33,238)**	**8,197**	**(25,041)**	(30,379)	3,562	(26,817)

[a]Including fair value of associated derivative financial instruments.

Revised definition of net debt

Net debt has been redefined to include the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed. The derivatives are reported on the balance sheet within the headings Derivative financial instruments . Amounts for comparative periods are presented on a consistent basis.

		$ million
		2007
	As amended	As reported
Net debt	26,817	27,483
Equity	94,652	94,652
Ratio of net debt to net debt plus equity	22%	23%

Notes on financial statements

37. Provisions

				$ million
	Decommissioning	**Environmental**	**Litigation and other**	**Total**
At 1 January 2008	**9,501**	**2,107**	**3,487**	**15,095**
Exchange adjustments	**(1,208)**	**(45)**	**(107)**	**(1,360)**
New or increased provisions	**327**	**270**	**2,059**	**2,656**
Write-back of unused provisions		**(107)**	**(513)**	**(620)**
Unwinding of discount	**202**	**43**	**42**	**287**
Utilization	**(402)**	**(512)**	**(1,424)**	**(2,338)**
Deletions	**(2)**	**(65)**		**(67)**
At 31 December 2008	**8,418**	**1,691**	**3,544**	**13,653**
Of which expected to be incurred within 1 year	**322**	**418**	**805**	**1,545**
expected to be incurred in more than 1 year	**8,096**	**1,273**	**2,739**	**12,108**

				$ million
	Decommissioning	Environmental	Litigation and other	Total
At 1 January 2007	8,365	2,127	3,152	13,644
Exchange adjustments	168	19	11	198
New or increased provisions	1,163	373	1,376	2,912
Write-back of unused provisions		(151)	(196)	(347)
Unwinding of discount	195	44	44	283
Utilization	(297)	(305)	(899)	(1,501)
Deletions	(93)		(1)	(94)
At 31 December 2007	9,501	2,107	3,487	15,095
Of which expected to be incurred within 1 year	447	431	1,317	2,195
expected to be incurred in more than 1 year	9,054	1,676	2,170	12,900

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. The provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or long-term assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 2.0% (2007 2.0%). These costs are generally expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs. Where BP has entered into a contract for the execution of decommissioning activity, these amounts are generally reported within accruals or other payables.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2007 2.0%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group s share of the liability.

Included within the litigation and other category at 31 December 2008 are provisions for litigation of $1,446 million (2007 $1,737 million), for deferred employee compensation of $792 million (2007 $761 million) and for expected rental shortfalls on surplus properties of $251 million (2007 $320 million). To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using either a nominal discount rate of 2.5% (2007 4.5%) or a real discount rate of 2.0% (2007 2.0%), as appropriate. No additional provisions were made during 2008 in respect of the Texas City incident (in 2007 the provision was increased by $500 million). Disbursements to claimants in 2008 were $410 million (2007 $314 million) and the provision at 31 December 2008 was $46 million (2007 $456 million).

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38. Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

In particular, the primary pension arrangement in the UK is a funded final salary pension plan that remains open to new employees. Retired employees draw the majority of their benefit as an annuity.

In the US, a range of retirement arrangements is provided. These include a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2008, contributions of $6 million (2007 $524 million and 2006 $438 million) and $362 million (2007 $97 million and 2006 $181 million) were made to the UK plans and US plans respectively. In addition, contributions of $130 million (2007 $127 million and 2006 $136 million) were made to other funded defined benefit plans. The aggregate level of contributions in all countries in 2009 is expected to be approximately $500 million, and includes contributions that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2008.

The material financial assumptions used for estimating the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension and other post-retirement benefits at 31 December. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2008 are used to determine the pension liabilities at that date and the pension expense for 2009.

			%						
Financial assumptions			UK			US			Other
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Discount rate for pension plan liabilities	**6.3**	5.7	5.1	**6.3**	6.1	5.7	**5.7**	5.6	4.8
Discount rate for post-retirement benefit plans	**n/a**	n/a	n/a	**6.2**	6.4	5.9	**n/a**	n/a	n/a
Rate of increase in salaries	**4.9**	5.1	4.7	**2.2**	4.2	4.2	**3.5**	3.7	3.6
Rate of increase for pensions in payment	**3.0**	3.2	2.8				**1.7**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.2	2.8				**1.0**	1.2	1.1
Inflation	**3.0**	3.2	2.8	**0.4**	2.4	2.4	**2.0**	2.2	2.2

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest schemes in the UK and US we use yields which reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US schemes are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase for deferred pensions where there is such an increase.

Our assumptions for the rate of increase in salaries are based on our inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 0.4% depending on country. In addition to the financial assumptions, we regularly review the demographic and mortality assumptions.

Notes on financial statements

38. Pensions and other post-retirement benefits continued
Mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. As part of the triannual valuation of our UK pensions funds, our UK mortality assumption was reviewed and updated at end-2008 resulting in an increase in the liability of around $900 million. BP s most substantial pension liabilities are in the UK, the US and Germany where our mortality assumptions are as follows:

									Years
Mortality assumptions			UK			US			Germany
	2008	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Life expectancy at age 60 for a male currently aged 60	**25.9**	24.0	23.9	**24.4**	24.3	24.2	**23.0**	22.4	22.2
Life expectancy at age 60 for a male currently aged 40	**28.9**	25.1	25.0	**25.9**	25.8	25.8	**25.9**	25.3	25.2
Life expectancy at age 60 for a female currently aged 60	**28.5**	26.9	26.8	**26.1**	26.1	26.0	**27.6**	27.0	26.9
Life expectancy at age 60 for a female currently aged 40	**31.4**	27.9	27.8	**27.0**	27.0	26.9	**30.3**	29.7	29.6

Our assumptions for future US healthcare cost trend rate reflect the rate of actual cost increases seen in recent years for the initial trend rate, and the ultimate trend rate reflects our long-term expectations based on past medical inflation seen over a longer period of time. The assumed future US healthcare cost trend rate is as follows:

			%
	2008	2007	2006
Initial US healthcare cost trend rate	**8.6**	9.0	9.3
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2015**	2013	2013

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligation of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

	Policy range

Asset category	%
Total equity	45-75
Bonds/cash	17.5-50
Property/real estate	0-10

Some of the group s pension plans use derivative financial instruments as part of their asset mix and to manage the level of risk. The group s main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary.

Return on asset assumptions reflect the group s expectations built up by asset class and by plan. The group s expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

Notes on financial statements

38. Pensions and other post-retirement benefits continued
The expected long-term rates of return and market values of the various categories of asset held by the defined benefit plans at 31 December are set out below. The market values shown include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. The market value of unlisted investments at 31 December 2008 was $2,819 million (2007 $2,491 million and 2006 $1,506 million). The market value of pension assets at the end of 2008 is lower than at the end of 2007 due to a fall in the market value of investments when expressed in their local currencies and a reduction in value that arises from changes in exchange rates (reducing the reported value of investments when expressed in US dollars). Movements in the value of plan assets during the year are shown in detail in the table on page 160.

		2008		2007		2006
	Expected long-term rate of return	**Market value**	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	%	**$ million**	%	$ million	%	$ million
UK pension plans						
Equities	**8.0**	**13,704**	8.0	24,106	7.5	23,631
Bonds	**6.1**	**3,258**	4.4	5,279	4.7	3,881
Property	**6.5**	**978**	6.5	1,259	6.5	1,370
Cash	**2.9**	**299**	5.6	977	3.8	379
	7.4	**18,239**	7.3	31,621	7.0	29,261
US pension plans						
Equities	**8.5**	**3,991**	8.5	6,610	8.5	6,528
Bonds	**3.7**	**1,247**	5.0	1,347	5.0	1,371
Property	**8.0**	**8**	8.0	16	8.0	15
Cash	**1.9**	**131**	3.6	72	3.2	41
	8.0	**5,377**	8.0	8,045	8.0	7,955
US other post-retirement benefit plans						
Equities	**8.5**	**9**	8.5	17	8.5	19
Bonds	**3.7**	**4**	5.0	6	5.0	7
	7.3	**13**	7.6	23	7.5	26
Other plans						
Equities	**8.4**	**799**	8.1	1,260	7.6	1,158
Bonds	**4.2**	**1,481**	5.0	1,491	4.6	1,199

Property	**6.3**	**127**	5.7	145	4.7	120
Cash	**3.1**	**118**	4.2	214	3.0	191
	5.8	**2,525**	6.4	3,110	5.8	2,668

The assumed rate of investment return, discount rate, inflation and the assumed US healthcare cost trend rate all have a significant effect on the amounts reported. A one-percentage point change in these assumptions for the group s plans would have had the following effects:

	$ million	
	One-percentage point	
	Increase	**Decrease**
Investment return		
Effect on pension and other post-retirement benefit expense in 2009	**(256)**	**258**
Discount rate		
Effect on pension and other post-retirement benefit expense in 2009	**(88)**	**129**
Effect on pension and other post-retirement benefit obligation at 31 December 2008	**(3,783)**	**4,818**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2009	**375**	**(286)**
Effect on pension and other post-retirement benefit obligation at 31 December 2008	**3,407**	**(2,783)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2009	**29**	**(23)**
Effect on US other post-retirement obligation at 31 December 2008	**335**	**(277)**

Notes on financial statements

38. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2008
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	**448**	**235**	**40**	**128**	**851**
Past service cost	**7**	**74**		**1**	**82**
Settlement, curtailment and special termination benefits	**30**			**12**	**42**
Payments to defined contribution plans		**170**		**25**	**195**
Total operating charge[b]	**485**	**479**	**40**	**166**	**1,170**
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	**2,094**	**632**	**2**	**194**	**2,922**
Interest on plan liabilities	**(1,239)**	**(444)**	**(198)**	**(450)**	**(2,331)**
Other finance income (expense)	**855**	**188**	**(196)**	**(256)**	**591**
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	**(6,946)**	**(2,895)**	**(8)**	**(404)**	**(10,253)**
Change in assumptions underlying the present value of the plan liabilities	**1,570**	**3**	**215**	**214**	**2,002**
Experience gains and losses arising on the plan liabilities	**(73)**	**(194)**	**18**	**70**	**(179)**
Actuarial (loss) gain recognized in statement of recognized income and expense	**(5,449)**	**(3,086)**	**225**	**(120)**	**(8,430)**
Movements in benefit obligation during the year					

Benefit obligation at 1 January	**23,927**	**7,409**	**3,178**	**8,586**	**43,100**
Exchange adjustments	**(6,408)**			**(628)**	**(7,036)**
Current service cost[a]	**448**	**235**	**40**	**128**	**851**
Past service cost	**7**	**74**		**1**	**82**
Interest cost	**1,239**	**444**	**198**	**450**	**2,331**
Curtailment				**(3)**	**(3)**
Settlement	**(3)**			**(3)**	**(6)**
Special termination benefits[c]	**33**			**18**	**51**
Contributions by plan participants	**42**			**12**	**54**
Benefit payments (funded plans)[d]	**(1,131)**	**(767)**	**(4)**	**(203)**	**(2,105)**
Benefit payments (unfunded plans)[d]	**(2)**	**(52)**	**(176)**	**(419)**	**(649)**
Actuarial (gain) loss on obligation	**(1,497)**	**191**	**(233)**	**(284)**	**(1,823)**
Benefit obligation at 31 December[a]	**16,655**	**7,534**	**3,003**	**7,655**	**34,847**
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	**31,621**	**8,045**	**23**	**3,110**	**42,799**
Exchange adjustments	**(7,447)**			**(314)**	**(7,761)**
Expected return on plan assets[a e]	**2,094**	**632**	**2**	**194**	**2,922**
Contributions by plan participants	**42**			**12**	**54**
Contributions by employers (funded plans)	**6**	**362**		**130**	**498**
Benefit payments (funded plans)[d]	**(1,131)**	**(767)**	**(4)**	**(203)**	**(2,105)**
Actuarial loss on plan assets[e]	**(6,946)**	**(2,895)**	**(8)**	**(404)**	**(10,253)**
Fair value of plan assets at 31 December	**18,239**	**5,377**	**13**	**2,525**	**26,154**
Surplus (deficit) at 31 December	**1,584**	**(2,157)**	**(2,990)**	**(5,130)**	**(8,693)**
Represented by					
Asset recognized	**1,682**			**56**	**1,738**
Liability recognized	**(98)**	**(2,157)**	**(2,990)**	**(5,186)**	**(10,431)**
	1,584	**(2,157)**	**(2,990)**	**(5,130)**	**(8,693)**
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	**1,682**	**(1,734)**	**(31)**	**(354)**	**(437)**
Unfunded	**(98)**	**(423)**	**(2,959)**	**(4,776)**	**(8,256)**
	1,584	**(2,157)**	**(2,990)**	**(5,130)**	**(8,693)**
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	**(16,557)**	**(7,111)**	**(44)**	**(2,879)**	**(26,591)**
Unfunded	**(98)**	**(423)**	**(2,959)**	**(4,776)**	**(8,256)**
	(16,655)	**(7,534)**	**(3,003)**	**(7,655)**	**(34,847)**

[a]The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b]Included within production and manufacturing expenses and distribution and administration expenses.

[c]The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[d]The benefit payments amount shown above comprises $2,697 million benefits plus $57 million of plan expenses incurred in the administration of the benefit.

[e]The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial loss on plan assets as disclosed above.

At 31 December 2008 reimbursement balances due from or to other companies in respect of pensions amounted to $455 million reimbursement assets (2007 $496 million) and $61 million reimbursement liabilities (2007 $72 million). These balances are not included as part of the pension liability, but are reflected elsewhere in the group balance sheet.

Notes on financial statements

38. Pensions and other post-retirement benefits continued

$ million

2007

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	492	227	43	132	894
Past service cost	5	10			15
Settlement, curtailment and special termination benefits	36			2	38
Payments to defined contribution plans		184		25	209
Total operating charge[b]	533	421	43	159	1,156
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	2,075	613	2	165	2,855
Interest on plan liabilities	(1,198)	(425)	(190)	(390)	(2,203)
Other finance income (expense)	877	188	(188)	(225)	652
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	406	(28)		(76)	302
Change in assumptions underlying the present value of the plan liabilities	513	358	137	607	1,615
Experience gains and losses arising on the plan liabilities	(162)	(27)	29	(40)	(200)
Actuarial gain recognized in statement of recognized income and expense	757	303	166	491	1,717
Movements in benefit obligation during the year					

Benefit obligation at 1 January	23,289	7,695	3,300	8,149	42,433
Exchange adjustments	394			917	1,311
Current service cost[a]	492	227	43	132	894
Past service cost	5	10			15
Interest cost	1,198	425	190	390	2,203
Curtailment	(7)				(7)
Settlement	(3)				(3)
Special termination benefits[c]	46			2	48
Contributions by plan participants	43			12	55
Benefit payments (funded plans)[d]	(1,085)	(580)	(5)	(182)	(1,852)
Benefit payments (unfunded plans)[d]	(3)	(37)	(184)	(379)	(603)
Acquisitions				141	141
Disposals	(91)			(29)	(120)
Actuarial gain on obligation	(351)	(331)	(166)	(567)	(1,415)
Benefit obligation at 31 December[a]	23,927	7,409	3,178	8,586	43,100
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	29,261	7,955	26	2,668	39,910
Exchange adjustments	488			316	804
Expected return on plan assets[a e]	2,075	613	2	165	2,855
Contributions by plan participants	43			12	55
Contributions by employers (funded plans)	524	97		127	748
Benefit payments (funded plans)[d]	(1,085)	(580)	(5)	(182)	(1,852)
Acquisitions				101	101
Disposals	(91)	(12)		(21)	(124)
Actuarial gain (loss) on plan assets[e]	406	(28)		(76)	302
Fair value of plan assets at 31 December	31,621	8,045	23	3,110	42,799
Surplus (deficit) at 31 December	7,694	636	(3,155)	(5,476)	(301)
Represented by					
Asset recognized	7,818	989		107	8,914
Liability recognized	(124)	(353)	(3,155)	(5,583)	(9,215)
	7,694	636	(3,155)	(5,476)	(301)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	7,818	978	(29)	(263)	8,504
Unfunded	(124)	(342)	(3,126)	(5,213)	(8,805)
	7,694	636	(3,155)	(5,476)	(301)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(23,803)	(7,067)	(52)	(3,373)	(34,295)
Unfunded	(124)	(342)	(3,126)	(5,213)	(8,805)

	(23,927)	(7,409)	(3,178)	(8,586)	(43,100)

[a]The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b]Included within production and manufacturing expenses and distribution and administration expenses.

[c]The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of a restructuring programme in the UK.

[d]The benefit payments amount shown above comprises $2,398 million benefits plus $57 million of plan expenses incurred in the administration of the benefit.

[e]The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.

Notes on financial statements

38. Pensions and other post-retirement benefits continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2006
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	432	216	42	139	829
Past service cost	(74)	38		39	3
Settlement, curtailment and special termination benefits	4			227	231
Payments to defined contribution plans		161		16	177
Total operating charge[b]	362	415	42	421	1,240
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,711	564	2	133	2,410
Interest on plan liabilities	(1,006)	(423)	(186)	(325)	(1,940)
Other finance income (expense)	705	141	(184)	(192)	470
Analysis of the amount recognized in the statement of recognized income and expense					
Actual return less expected return on pension plan assets	1,305	521		141	1,967
Change in assumptions underlying the present value of the plan liabilities	114	195	111	352	772
Experience gains and losses arising on the plan liabilities	(24)	17	80	(197)	(124)
Actuarial gain recognized in statement of recognized income and expense	1,395	733	191	296	2,615

[a]The costs of managing the plan s investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are generally included in current service cost, and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

[b]Included within production and manufacturing expenses and distribution and administration expenses.

					$ million
	2008	2007	2006	2005	2004
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**34,847**	43,100	42,433	38,855	39,945
Fair value of plan assets at 31 December	**26,154**	42,799	39,910	32,907	31,712
Deficit	**(8,693)**	(301)	(2,523)	(5,948)	(8,233)
Experience losses on plan liabilities	**(178)**	(200)	(124)	(212)	(468)
Actual return less expected return on pension plan assets	**(10,253)**	302	1,967	3,364	1,349
Actual return on plan assets	**(7,331)**	3,157	4,377	5,502	3,332
Actuarial (loss) gain recognized in statement of recognized income and expense	**(8,430)**	1,717	2,615	975	107
Cumulative amount recognized in statement of recognized income and expense	**(2,940)**	5,490	3,773	1,158	183

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2018 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2009	**941**	**795**	**194**	**525**	**2,455**
2010	**969**	**798**	**200**	**512**	**2,479**
2011	**942**	**771**	**207**	**506**	**2,426**
2012	**941**	**787**	**211**	**506**	**2,445**
2013	**941**	**754**	**214**	**496**	**2,405**
2014-2018	**4,704**	**3,645**	**1,111**	**2,501**	**11,961**

Notes on financial statements

39. Called-up share capital
The allotted, called-up and fully paid share capital at 31 December was as follows:

		2008		2007		2006
Issued	**Shares (thousand)**	**$ million**	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,863,424**	**5,216**	21,457,301	5,364	20,657,045	5,164
Issue of new shares for employee share schemes	**24,791**	**6**	69,273	18	64,854	16
Issue of ordinary share capital for TNK-BP					111,151	28
Repurchase of ordinary share capital	**(269,757)**	**(67)**	(663,150)	(166)	(358,374)	(90)
Other[a]					982,625	246
At 31 December	**20,618,458**	**5,155**	20,863,424	5,216	21,457,301	5,364
		5,176		5,237		5,385
Authorized						
8% cumulative first preference shares of £1 each	**7,250**	**12**	7,250	12	7,250	12
9% cumulative second preference shares of £1 each	**5,500**	**9**	5,500	9	5,500	9
Ordinary shares of 25 cents each	**36,000,000**	**9,000**	36,000,000	9,000	36,000,000	9,000

[a]Reclassification in respect of share repurchases in 2005.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

Repurchase of ordinary share capital

The company purchased 269,757,188 ordinary shares (2007 663,149,528 and 2006 1,334,362,750 ordinary shares) for a total consideration of $2,914 million (2007 $7,497 million and 2006 $15,481 million), all of which were for cancellation. At 31 December 2008, 150,444,408 (2007 150,966,096 and 2006 99,045,000) ordinary shares bought back were awaiting cancellation. These shares have been excluded from ordinary shares in issue shown above. At 31 December 2008, 1,888,151,157 shares of nominal value $472 million were held in treasury (2007 1,940,638,808 shares of nominal value $485 million). The maximum number of shares held in treasury during the year was 1,940,638,808 shares of nominal value $485 million (2007 1,946,804,533 shares of nominal value $487 million), representing 9.3% (2007 9.1%) of the called-up ordinary share capital of the company.

During 2008, 10,000,000 treasury shares (2007 1,700,000 treasury shares) were gifted to the Employee Share Ownership Plans (ESOPs), 20,000,000 treasury shares were transferred at market price to the ESOPs, and 22,487,651 treasury shares (2007 4,465,725 treasury shares) were reissued in relation to employee share schemes, in total representing 0.25% (2007 less than 0.1%) of the ordinary share capital of the company. The nominal value of these shares was $13 million (2007 $2 million) and the total proceeds received from the re-issues in relation to employee share schemes were $75 million (2007 $35 million).

Transaction costs of share repurchases amounted to $16 million (2007 $40 million and 2006 $83 million).

Notes on financial statements

40. Capital and reserves

	Share capital	**Share premium account**	**Capital redemption reserve**
At 1 January 2008	**5,237**	**9,581**	**1,005**
Recognized income and expense			
Currency translation differences (net of tax)			
Actuarial loss relating to pension and other post-retirement benefits (net of tax)			
Available-for-sale investments marked to market (net of tax)			
Available-for-sale investments recycling (net of tax)			
Cash flow hedges marked to market (net of tax)			
Cash flow hedges recycling (net of tax)			
Tax on share-based payments			
Profit for the year			
Total recognized income and expense for the year			
Dividends			
Repurchase of ordinary share capital	**(67)**		**67**
Share-based payments	**6**	**182**	
Minority interest buyout			
At 31 December 2008	**5,176**	**9,763**	**1,072**

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2007	5,385	9,074	839
Recognized income and expense			
Currency translation differences (net of tax)			
Exchange gain on translation of foreign operations transferred to (profit) or loss on sale (net of tax)			
Actuarial gain relating to pension and other post-retirement benefits (net of tax)			
Available-for-sale investments marked to market (net of tax)			

Available-for-sale investments recycling (net of tax)			
Cash flow hedges marked to market (net of tax)			
Cash flow hedges recycling (net of tax)			
Tax on share-based payments			
Profit for the year			
Total recognized income and expense for the year			
Dividends			
Repurchase of ordinary share capital	(166)		166
Share-based payments	18	507	
At 31 December 2007	5,237	9,581	1,005

	Share capital	Share premium account	Capital redemption reserve
At 1 January 2006	5,185	7,371	749
Recognized income and expense			
Currency translation differences (net of tax)			
Actuarial gain relating to pension and other post-retirement benefits (net of tax)			
Available-for-sale investments marked to market (net of tax)			
Available-for-sale investments recycling (net of tax)			
Cash flow hedges marked to market (net of tax)			
Cash flow hedges recycling (net of tax)			
Tax on share-based payments			
Profit for the year			
Total recognized income and expense for the year			
Dividends			
Repurchase of ordinary share capital	(90)		90
Issue of ordinary share capital for TNK-BP	28	1,222	
Share-based payments	16	481	
Other[b]	246		
Currency translation differences (net of tax)			
At 31 December 2006	5,385	9,074	839

[a]At 31 December 2006, the foreign currency translation reserve included $122 million relating to non-current assets held for sale. During 2007, this was included in the $147 million recycled to the income statement relating to disposals in 2007. For further details see Note 5.

[b]Reclassification in respect of share repurchases in 2005.

Notes on financial statements

$ million

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,206		**(60)**	**(22,112)**	**6,540**	**481**	**106**	**1,196**	**64,510**	**93,690**	**962**	**94,652**
				(4,187)					**(4,187)**	**(75)**	**(4,262)**
								(5,828)	**(5,828)**		**(5,828)**
					(944)				**(944)**		**(944)**
					526				**526**		**526**
						(984)			**(984)**		**(984)**
						12			**12**		**12**
							(190)		**(190)**		**(190)**
								21,157	**21,157**	**509**	**21,666**
				(4,187)	**(418)**	**(972)**	**(190)**	**15,329**	**9,562**	**434**	**9,996**
								(10,342)	**(10,342)**	**(425)**	**(10,767)**
								(2,414)	**(2,414)**		**(2,414)**
		(266)	**599**				**289**	**(3)**	**807**		**807**
										(165)	**(165)**
27,206		**(326)**	**(21,513)**	**2,353**	**63**	**(866)**	**1,295**	**67,080**	**91,303**	**806**	**92,109**

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,201	5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465
				2,002					2,002	24	2,026
				(147)					(147)		(147)
								1,290	1,290		1,290
					152				152		152
					(57)				(57)		(57)

						138			138		138
						(71)			(71)		(71)
							213		213		213
								20,845	20,845	324	21,169
				1,855	95	67	213	22,135	24,365	348	24,713
								(8,106)	(8,106)	(227)	(8,333)
								(7,997)	(7,997)		(7,997)
5	(5)	94	70				124	(9)	804		804
27,206		(60)	(22,112)	6,540	481	106	1,196	64,510	93,690	962	94,652

Merger reserve	Other reserve	Own shares	Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
27,190	16	(140)	(10,598)	2,943	385	(234)	643	46,151	79,661	789	80,450
				1,742	27	6			1,775	49	1,824
								1,795	1,795		1,795
					478				478		478
					(504)				(504)		(504)
						313			313		313
						(46)			(46)		(46)
							26		26		26
								22,315	22,315	286	22,601
				1,742	1	273	26	24,110	26,152	335	26,487
								(7,686)	(7,686)	(283)	(7,969)
			(11,472)					(4,009)	(15,481)		(15,481)
									1,250		1,250
11	(11)	5	134				190	(79)	747		747
			(246)								
		(19)							(19)		(19)
27,201	5	(154)	(22,182)	4,685	386	39	859	58,487	84,624	841	85,465

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Notes on financial statements

40. Capital and reserves continued

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

Other reserve

The balance on the other reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in the ARCO acquisition on the exercise of ARCO share options.

Own shares

Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans.

Treasury shares

Treasury shares represent BP shares repurchased and available for re-issue.

Foreign currency translation reserve

The foreign currency translation reserve is used to record exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement. This reserve is also used to record the effect of hedging net investments in foreign operations.

Available-for-sale investments

This reserve records the changes in fair value of available-for-sale investments. On disposal, or impairment, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges

This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. When the hedged transaction occurs, the gain or loss on the hedging instrument is transferred out of equity to either profit or loss or the carrying value of assets, as appropriate. If the forecast transaction is no longer expected to occur the gain or loss recognized in equity is transferred to profit or loss.

Share-based payment reserve

This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Profit and loss account

The balance held on this reserve is the accumulated retained profits of the group.

41. Share-based payments

Effect of share-based payment transactions on the group s result and financial position

			$ million
	2008	2007	2006

Total expense recognized for equity-settled share-based payment transactions	**524**	412	405
Total (credit) expense recognized for cash-settled share-based payment transactions	**(16)**	16	14
Total expense recognized for share-based payment transactions	**508**	428	419
Closing balance of liability for cash-settled share-based payment transactions	**21**	40	38
Total intrinsic value for vested cash-settled share-based payments	**2**	22	23

For ease of presentation, option and share holdings detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted American Depositary Shares (ADSs) or options over the company s ADSs (one ADS is equivalent to six ordinary shares). The share-based payment plans that existed during the year are detailed below. All plans are ongoing unless otherwise stated.

Notes on financial statements

41. Share-based payments continued

Plans for executive directors

Executive Directors Incentive Plan (EDIP) share element

An equity-settled incentive share plan for executive directors driven by one performance measure over a three-year performance period. The award of shares is determined by comparing BP s total shareholder return (TSR) against the other oil majors. After the performance period, the shares that vest (net of tax) are then subject to a three-year retention period. In February 2008 it was considered appropriate to strengthen the retention element of remuneration for two executive directors. The remuneration committee granted, on a one-off basis, a restricted share award to those two executive directors. The shares will vest subject to continued service, in equal tranches, after three and five years. Vesting of each tranche is dependent on the committee being satisfied, at each vesting date, with the performance of the individuals. These retention awards have been granted under EDIP which permits awards to be made, on an exceptional basis, subject to a requirement of continued service over a specific period. The directors remuneration report on pages 73 to 83 includes full details of this plan.

Executive Directors Incentive Plan (EDIP) share option element

An equity-settled share option plan for executive directors that permits options to be granted at an exercise price no lower than the market price of a share on the date that the option is granted. Options vest over three years (one-third each after one, two and three years respectively) and must be exercised within seven years of the date of grant. Last grants were made in 2004. From 2005 onwards the remuneration committee s policy is not to make further grants of share options to executive directors.

Plans for senior employees

Medium Term Performance Plan (MTPP)

An equity-settled restricted share unit plan for senior employees driven by two performance measures over a three-year performance period. At the end of the performance period units are converted into shares. The amount of units converted to shares is determined by comparing BP s TSR against the other oil majors and, additionally, by comparing free cash flow (FCF) against a threshold established for the period. For a small group of particularly senior employees only the TSR measure is applicable in determining the award. The number of units converted into shares is increased to take account of the net notional dividends that would have been received during the performance period, assuming that such dividends would have been reinvested. With regard to leaver provisions the general rule is that leaving employment during the performance period will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after completion of the first year of the performance period. The current policy of the company, which is reflected in the terms of the MTPP, is that senior employees subject to the plan should meet a minimum shareholding requirement. Grants will not be made under this plan after 2008.

Senior Employees Deferred Annual Bonus Plan (DAB)

An equity-settled restricted share unit plan for senior employees. In 2008 the grant value is equal to 50% (2007 and 2006 50%) of the annual cash bonus awarded for the preceding performance year (the performance period). For 2009 this will increase to 100%. The units are restricted for a period of three years (the restriction period), during which they accrue net notional dividends which are treated as having been reinvested. At the end of the restriction period units are converted into shares. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the performance period the general rule is that this will preclude the grant of units. If a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason.

Integrated Supply and Trading Deferred Annual Bonus Plan (IST DAB)

An equity-settled restricted share unit plan for traders in the IST function. The plan operates under the DAB but the rules differ in certain respects from that plan. If eligible, a portion of a trader s annual cash bonus (the base grant), awarded for the preceding performance year (the performance period), plus an additional 25% of that amount (the additional grant),will be deferred in restricted share units. The units are restricted over a period of three calendar years, during which they accrue net notional dividends, which are treated as having been reinvested. At the end of the restriction period units are converted into shares. One third of the base grant vests after one and two calendar years respectively, with the final third plus the additional grant vesting after three calendar years. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. Special arrangements apply where the participant leaves for a qualifying reason.

Performance Share Plan (PSP)

An equity-settled restricted share unit plan for senior professionals and team leaders. The grant takes into account the recipient s performance in the prior calendar year (the performance period). The units are restricted for a period of three years (the restriction period), during which they accrue net notional dividends, which are treated as having been reinvested. At the end of the restriction period additional units may be awarded based on BP s TSR performance against the other oil majors. At the end of the restriction period units are converted into shares. With regard to leaver provisions the general rule is that leaving during the performance period will preclude the grant of units. If a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. Special arrangements apply where the participant leaves for a qualifying reason.

Restricted Share Plan (RSP)

An equity-settled restricted share unit plan used predominantly for senior employees in special circumstances (such as recruitment and retention). There are generally no performance conditions but the units are subject to a three-year restriction period, during which they accrue net notional dividends which are treated as having been reinvested. At the end of the restricted period the units are converted into shares. With regard to leaver provisions, if a participant ceases to be employed by BP prior to the end of the restriction period the general rule is that this will preclude the conversion of units into shares. However, special arrangements apply where the participant leaves for a qualifying reason.

Notes on financial statements

41. Share-based payments continued

BP Share Option Plan (BPSOP)

An equity-settled share option plan that applies to certain categories of employees. Participants are granted share options with an exercise price no lower than the market price of a share immediately preceding the date of grant. There are no performance conditions and the options are exercisable between the third and tenth anniversaries of the grant date. The general rule is that the options will lapse if the participant leaves employment before the end of the third calendar year from the date of grant (and that vested options are exercisable within $3^1/_2$ years from the date of leaving). However, special arrangements apply where the participant leaves for a qualifying reason and employment ceases after the end of the calendar year of the date of grant. From 2007 share options no longer form a regular element of our incentive plans.

Savings and matching plans

BP ShareSave Plan

This is a savings-related share option plan under which employees save on a monthly basis, over a three-year or five-year period, towards the purchase of shares at a fixed price determined when the option is granted. This price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and options are granted annually, usually in June. Participants leaving for a qualifying reason will have six months in which to use their savings to exercise their options on a pro rated basis.

BP ShareMatch Plans

These are matching share plans under which BP matches employees own contributions of shares up to a predetermined limit. The plans are run in the UK and in more than 70 other countries. The UK plan is run on a monthly basis with shares being held in trust for five years before they can be released free of any income tax and national insurance liability. In other countries the plan is run on an annual basis with shares being held in trust for three years. The plan is operated on a cash basis in those countries where there are regulatory restrictions preventing the holding of BP shares. When the employee leaves BP all shares must be removed from trust and units under the plan operated on a cash basis must be encashed.

Local plans

In some countries BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances.

The above share plans are indicated as being equity-settled. In certain countries however, it is not possible to award shares to employees owing to local legislation. In these instances the award will be settled in cash, calculated as the cash equivalent of the value to the employee of an equity-settled plan.

Cash plans

Cash-settled share-based payments/Stock Appreciation Rights (SARs)

These are cash-settled share-based payments available to certain employees that require the group to pay the intrinsic value of the cash option/SAR/restricted shares to the employee at the date of exercise or on maturity. The cash options/SARs have the same rules as the BPSOP plan and the cash restricted share plans (MTPP, DAB, PSP, RSP) have the same rules as their equity-settled counterparts.

Employee Share Ownership Plans (ESOPs)

ESOPs have been established to acquire BP shares to satisfy any awards made to participants under the BP share plans as required. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company s own shares held by the ESOP trusts vest unconditionally to employees, the amount paid for those shares is deducted in arriving at shareholders equity (see Note 40). Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2008 the ESOPs held 29,051,082 shares (2007 6,448,838 shares and 2006 12,795,887 shares) for potential future awards, which had a market value of $220 million (2007 $79 million and 2006 $142 million).

Share option transactions		**2008**		2007		2006
	Number of options	**Weighted average exercise price $**	Number of options	Weighted average exercise price $	Number of options	Weighted average exercise price $
Outstanding at 1 January	**358,094,243**	**8.51**	426,471,462	8.25	450,453,502	7.64
Granted	**8,062,899**	**8.96**	6,004,025	9.11	53,977,639	11.18
Forfeited	**(2,502,784)**	**8.50**	(3,924,714)	9.10	(7,169,710)	8.69
Exercised	**(37,277,895)**	**6.97**	(69,715,558)	6.94	(70,658,480)	6.52
Expired	**(121,864)**	**7.00**	(740,972)	8.68	(131,489)	7.99
Outstanding at 31 December	**326,254,599**	**8.70**	358,094,243	8.51	426,471,462	8.25
Exercisable at 31 December	**260,178,938**	**8.22**	238,707,055	7.70	236,726,966	7.41

Notes on financial statements

41. Share-based payments continued
As share options are exercised continuously throughout the year, the weighted average share price during the year of $10.87 (2007 $11.72 and 2006 $11.85) is representative of the weighted average share price at the date of exercise. For the options outstanding at 31 December 2008, the exercise price ranges and weighted average remaining contractual lives are shown below.

	Options outstanding			**Options exercisable**	
Range of exercise prices	**Number of shares**	**Weighted average remaining life Years**	**Weighted average exercise price $**	**Number of shares**	**Weighted average exercise price $**
$5.71 $7.25	**51,430,951**	**3.81**	**6.39**	**48,919,680**	**6.35**
$7.26 $8.80	**159,708,260**	**3.12**	**8.11**	**157,933,135**	**8.11**
$8.81 $10.36	**42,960,673**	**4.53**	**9.53**	**26,083,268**	**9.83**
$10.37 $11.92	**72,154,715**	**6.81**	**11.14**	**27,242,855**	**10.67**
	326,254,599	**4.23**	**8.70**	**260,178,938**	**8.22**

Fair values and associated details for options and shares granted

Options granted in 2008	**ShareSave 3 year**	**ShareSave 5 year**
Option pricing model used	**Binomial**	**Binomial**
Weighted average fair value	**$1.82**	**$1.74**
Weighted average share price	**$11.26**	**$11.26**
Weighted average exercise price	**$9.70**	**$9.70**
Expected volatility	**23%**	**23%**
Option life	**3.5 years**	**5.5 years**
Expected dividends	**4.60%**	**4.60%**
Risk free interest rate	**5.00%**	**5.00%**
Expected exercise behaviour	**100% year 4**	**100% year 6**

Options granted in 2007	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial
Weighted average fair value	$3.57	$3.79

Weighted average share price	$12.10	$12.10
Weighted average exercise price	$9.13	$9.13
Expected volatility	21%	21%
Option life	3.5 years	5.5 years
Expected dividends	3.48%	3.48%
Risk free interest rate	5.75%	5.75%
Expected exercise behaviour	100% year 4	100% year 6

Options granted in 2006	BPSOP	ShareSave 3 year	ShareSave 5 year
Option pricing model used	Binomial	Binomial	Binomial
Weighted average fair value	$2.46	$2.88	$3.08
Weighted average share price	$11.07	$11.08	$11.08
Weighted average exercise price	$11.17	$9.10	$9.10
Expected volatility	22%	24%	24%
Option life	10 years	3.5 years	5.5 years
Expected dividends	3.23%	3.40%	3.40%
Risk free interest rate	4.50%	5.00%	4.75%
Expected exercise behaviour	5% years 4-9, 70% year 10	100% year 4	100% year 6

The group uses an appropriate valuation model of expected volatility of US ADSs for the quarter within which the grant date of the relevant plan falls. Management is responsible for all inputs and assumptions in relation to that model, including the determination of expected volatility.

Shares granted in 2008	**MTPP-TSR**	**MTPP-FCF**	**EDIP-TSR**	**EDIP-RET**	**RSP**	**DAB**	**PSP**
Number of equity instruments granted (million)	**9.1**	**9.1**	**2.6**	**0.5**	**7.7**	**5.8**	**16.7**
Weighted average fair value	**$5.07**	**$10.34**	**$4.55**	**$11.13**	**$8.83**	**$10.34**	**$12.89**
Fair value measurement basis	**Monte Carlo**	**Market value**	**Monte Carlo**	**Market value**	**Market value**	**Market value**	**Monte Carlo**

Notes on financial statements

41. Share-based payments continued

Shares granted in 2007	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL	RSP	DAB	PSP
Number of equity instruments granted (million)	9.4	8.5	4.5	0.5	7.7	4.4	14.8
Weighted average fair value	$4.73	$10.02	$2.81	$9.92	$11.93	$10.02	$12.37
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value	Monte Carlo

Shares granted in 2006	MTPP-TSR	MTPP-FCF	EDIP-TSR	EDIP-LTL	RSP	DAB
Number of equity instruments granted (million)	8.7	7.8	3.3	0.5	0.5	3.5
Weighted average fair value	$7.28	$11.23	$4.87	$11.23	$11.07	$11.06
Fair value measurement basis	Monte Carlo	Market value	Monte Carlo	Market value	Market value	Market value

The group used a Monte Carlo simulation to fair value the TSR element of the 2008, 2007 and 2006 PSP, MTPP and EDIP plans. In accordance with the rules of the plans the model simulates BP s TSR and compares it against our principal strategic competitors over the three-year period of the plans. The model takes into account the historic dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the actual value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

42. Employee costs and numbers

			$ million
Employee costs	**2008**	2007	2006
Wages and salaries[a c]	**10,388**	9,808	8,703
Social security costs	**805**	771	751
Share-based payments	**508**	428	419
Pension and other post-retirement benefit costs	**579**	504	770
	12,280	11,511	10,643

Number of employees at 31 December	**2008**	2007	2006
Exploration and Production	**21,400**	21,800	21,400
Refining and Marketing[b c]	**61,500**	67,200	68,000
Other businesses and corporate[c]	**9,100**	9,100	7,600
	92,000	98,100	97,000

By geographical area			
UK	**15,900**	17,000	16,900
Rest of Europe	**19,400**	19,900	20,200
US	**29,300**	33,000	33,700
Rest of World[b]	**27,400**	28,200	26,200
	92,000	98,100	97,000

					2008					2007
Average number of employees	**UK**	**Rest of Europe**	**US**	**Rest of World**	**Total**	UK	Rest of Europe	US	Rest of World	Total
Exploration and Production	**3,700**	**700**	**7,800**	**9,400**	**21,600**	3,800	700	7,700	9,300	21,500
Refining and Marketing	**9,300**	**18,300**	**21,600**	**15,800**	**65,000**	10,300	18,600	23,400	15,000	67,300
Other businesses and corporate	**3,400**	**800**	**2,600**	**2,300**	**9,100**	2,600	900	2,500	2,400	8,400
	16,400	**19,800**	**32,000**	**27,500**	**95,700**	16,700	20,200	33,600	26,700	97,200

[a]Includes termination payments of $669 million (2007 $422 million and 2006 $257 million). A restructuring was announced in October 2007, the implementation of which continues in 2009.

[b] Includes 21,200 (2007 24,500 and 2006 26,100) service station staff.

[c]A minor amendment has been made to the comparative figures to include some employee costs which had been previously incorrectly excluded and to correct headcount data.

Notes on financial statements

42. Employee costs and numbers continued

Average number of employees	UK	Rest of Europe	US	Rest of World	Total
					2006
Exploration and Production	3,500	800	7,100	9,000	20,400
Refining and Marketing	11,100	19,300	24,800	14,100	69,300
Other businesses and corporate	2,200	800	2,600	1,800	7,400
	16,800	20,900	34,500	24,900	97,100

43. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2008	2007	2006
Total for all directors			
Emoluments	**19**	26	14
Gains made on the exercise of share options	**1**	2	12
Amounts awarded under incentive schemes		10	14

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year. This includes an ex gratia superannuation payment of nil (2007 $3 million and 2006 nil) and compensation for loss of office of $1 million (2007 $1 million and 2006 nil).

Pension contributions

Four executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2008.

Office facilities for former chairmen and deputy chairmen

It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information

Full details of individual directors   remuneration are given in the directors   remuneration report on pages 73 to 83.

Remuneration of senior management

$ million

	2008	2007	2006
Total for all senior management			
Short-term employee benefits	**40**	37	30
Post-retirement benefits	**4**	7	4
Share-based payments	**20**	22	26

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits

In addition to fees paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus bonuses awarded for the year. This includes an ex gratia superannuation payment of nil (2007 $3 million and 2006 nil) and compensation for loss of office of $3 million (2007 $1 million and 2006 $5 million).

Post-retirement benefits

The amounts represent the estimated cost to the group of providing defined benefit pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 Employee Benefits .

Share-based payments

This is the cost to the group of senior management s participation in share-based payment plans, as measured by the fair value of options and shares granted accounted for in accordance with IFRS 2 Share-based Payments . The main plans in which senior management have participated are the EDIP, MTPP and LTPP. For details of these plans refer to Note 41.

Notes on financial statements

44. Contingent liabilities

There were contingent liabilities at 31 December 2008 in respect of guarantees and indemnities entered into as part of the ordinary course of the group s business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 28.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously. It is not possible to estimate any financial effect.

Since 1987, Atlantic Richfield, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies, including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education on lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and thus the incurrence of a liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the group s results of operations, financial position or liquidity will not be material.

In addition, various group companies are parties to legal actions and claims that arise in the ordinary course of the group s business. While the outcome of such legal proceedings cannot be readily foreseen, BP believes that they will be resolved without material effect on the group s results of operations, financial position or liquidity. The group files income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group s income tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group s results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group s accounting policies. While the amounts of future costs could be significant and could be material to the group s results of operations in the period in which they are recognized, it is not practical to estimate the amounts involved. BP does not expect these costs to have a material effect on the group s financial position or liquidity.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

45. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been placed at 31 December 2008 amounted to $14,062 million (2007 $8,263 million). In addition, at 31 December 2008, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $644 million (2007 $1,039 million) and investments in associates of $160 million (2007 $74 million).

Capital commitments of jointly controlled entities amounted to $1,540 million (2007 $2,273 million).

Notes on financial statements

46. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2008 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company s country of incorporation or by its name. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, jointly controlled entities and associates will be attached to the parent company s annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England	Investment holding
BP Exploration Op. Co.	100	England	Exploration and production
*BP Global Investments	100	England	Investment holding
*BP International	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
*BP Shipping	100	England	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Oil Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production

Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Indonesia			
BP Berau	100	US	Exploration and production
BP West Java	100	US	Exploration and production

Subsidiaries	%	Country of incorporation	Principal activities
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
UK			

BP Capital Markets	100	England	Finance
BP Oil UK	100	England	Marketing
Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
US			
*BP Holdings North America	100	England	Investment holding
Atlantic Richfield Co.			
BP America			Exploration and
BP America Production Company			production, refining
			and marketing, pipelines
BP Amoco Chemical Company	100	US	and petrochemicals
BP Company North America			
BP Corporation North America			
BP Exploration (Alaska) Inc.			
BP Products North America			
BP West Coast Products			
Standard Oil Co.			
BP Capital Markets America			Finance

Notes on financial statements

46. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation or registration	Principal activities
Angola LNG Supply Services	14	US	LNG processing and transportation
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
BP-Husky Refining	50	US	Refining
Elvary Neftegaz Holdings BV	49	Netherlands	Exploration and appraisal
Fowler 1 Holdings	50	US	Wind farm development
LukArco	46	Netherlands	Exploration and production, pipelines
Pan American Energy[a]	60	US	Exploration and production
Petromonagas	17	Venezuela	Exploration and production
Ruhr Oel	50	Germany	Refining and marketing and petrochemicals
Shanghai SECCO Petrochemical Co.	50	China	Petrochemicals
Sunrise Oil Sands	50	Canada	Exploration and production
TNK-BP	50	British Virgin Islands	Integrated oil operations
United Gas Derivatives Company	33	Egypt	NGL extraction

[a] Pan American Energy is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity rather than a subsidiary.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co.	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
South Caucasus Pipeline Co.	26	Cayman Islands	Pipelines
Trinidad & Tobago			
Atlantic LNG Company of Trinidad and Tobago	34	Trinidad & Tobago	LNG manufacture

Notes on financial statements

47. Oil and natural gas exploration and production activities[a]

$ million

2008

	UK	**Rest of Europe**	**US**	**Rest of Americas**	**Asia Pacific**	**Africa**	**Russia**	**Other**	**Total**
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	**34,614**	**5,507**	**59,918**	**11,451**	**4,720**	**21,563**		**8,550**	**146,323**
Unproved properties	**626**		**5,006**	**299**	**1,019**	**2,011**		**464**	**9,425**
	35,240	**5,507**	**64,924**	**11,750**	**5,739**	**23,574**		**9,014**	**155,748**
Accumulated depreciation	**26,564**	**3,125**	**28,511**	**6,358**	**2,181**	**10,451**		**3,159**	**80,349**
Net capitalized costs	**8,676**	**2,382**	**36,413**	**5,392**	**3,558**	**13,123**		**5,855**	**75,399**

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2008 was $13,393 million.

	UK	**Rest of Europe**	**US**	**Rest of Americas**	**Asia Pacific**	**Africa**	**Russia**	**Other**	**Total**
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved			**1,374**	**2**				**136**	**1,512**
Unproved	**4**		**2,942**					**41**	**2,987**
	4		**4,316**	**2**				**177**	**4,499**
Exploration and appraisal costs[b]	**137**		**862**	**123**	**79**	**838**	**12**	**239**	**2,290**
Development	**907**	**695**	**4,914**	**1,077**	**465**	**2,966**		**743**	**11,767**
Total costs	**1,048**	**695**	**10,092**	**1,202**	**544**	**3,804**	**12**	**1,159**	**18,556**

The group s share of jointly controlled entities and associates costs incurred in 2008 was $3,259 million: in Russia $1,921 million, Rest of Americas $1,039 million, Asia Pacific $24 million and other $275 million.

Results of operations for the year ended 31 December

Sales and other operating revenues									
Third parties	3,865	105	8,010	3,573	1,410	3,745		549	21,257
Sales between businesses	4,374	1,416	15,610	3,755	1,420	6,022		11,087	43,684
	8,239	1,521	23,620	7,328	2,830	9,767		11,636	64,941
Exploration expenditure	121	1	305	62	41	213	14	125	882
Production costs	1,357	150	3,002	718	213	875	18	334	6,667
Production taxes	503		2,603	360	110			3,083	6,659
Other costs (income)[c]	(28)	(43)	3,440	541	309	245	196	4,041	8,701
Depreciation, depletion and amortization	1,049	199	2,729	911	251	2,120		624	7,883
Impairments and (gains) losses on sale of businesses and fixed assets			308	6	219	8			541
	3,002	307	12,387	2,598	1,143	3,461	228	8,207	31,333
Profit before taxation[d]	5,237	1,214	11,233	4,730	1,687	6,306	(228)	3,429	33,608
Allocable taxes	2,280	883	3,857	2,423	618	2,672	(36)	879	13,576
Results of operations	2,957	331	7,376	2,307	1,069	3,634	(192)	2,550	20,032

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2008 was a profit of $2,793 million after deducting interest of $355 million, taxation of $1,217 million and minority interest of $169 million.

Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	5,237	1,214	11,233	4,730	1,687	6,306	(228)	3,429	33,608
Jointly controlled entities and associates	(1)		1	344	48	(1)	2,259	143	2,793
Midstream activities[e]	743	16	425	619	(228)	112		(173)	1,514
Total profit before interest and tax	5,979	1,230	11,659	5,693	1,507	6,417	2,031	3,399	37,915

[a]This note contains information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most

significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola. The group s share of jointly controlled entities and associates activities are excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the results of operations above.

[b]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c]Includes property taxes, other government take and the fair value loss on embedded derivatives of $102 million. The UK region includes a $499 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[d]Excludes the unwinding of the discount on provisions and payables amounting to $285 million which is included in finance costs in the group income statement.

[e]Includes a $517 million write-down of our investment in Rosneft based on its quoted market price at the end of the year.

Notes on financial statements

47. Oil and natural gas exploration and production activities[a] continued

$ million

2007

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	34,774	4,925	53,079	10,627	3,528	18,333		7,596	132,862
Unproved properties	606		1,660	297	1,188	1,533	4	349	5,637
	35,380	4,925	54,739	10,924	4,716	19,866	4	7,945	138,499
Accumulated depreciation	25,515	2,925	25,500	5,528	1,508	8,315		2,553	71,844
Net capitalized costs	9,865	2,000	29,239	5,396	3,208	11,551	4	5,392	66,655

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2007 was $11,787 million.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved			245					232	477
Unproved			54	16		321		126	517
			299	16		321		358	994
Exploration and appraisal costs[b]	209	16	646	72	51	677	119	102	1,892
Development costs	804	443	3,861	1,057	333	2,634		1,021	10,153
Total costs	1,013	459	4,806	1,145	384	3,632	119	1,481	13,039

The group s share of jointly controlled entities and associates costs incurred in 2007 was $2,552 million: in Russia $1,787 million, Rest of Americas $569 million, Asia Pacific $17 million and other $179 million.

Results of operations for the year ended 31 December									
Sales and other operating revenues									
Third parties	4,503	434	1,436	2,142	1,148	2,219		921	12,803
Sales between businesses	2,260	902	14,353	3,142	970	3,223		9,983	34,833
	6,763	1,336	15,789	5,284	2,118	5,442		10,904	47,636
Exploration expenditure	46		252	134	11	183	116	14	756
Production costs	1,658	147	2,782	770	190	637	2	344	6,530
Production taxes	227	3	1,260	273	56			2,224	4,043
Other costs (income)[c]	(419)	123	2,505	395	378	200	169	3,018	6,369
Depreciation, depletion and amortization	1,569	207	2,118	822	205	1,372		995	7,288
Impairments and (gains) losses on sale of businesses and fixed assets	112	(534)	(413)	(43)		(76)			(954)
	3,193	(54)	8,504	2,351	840	2,316	287	6,595	24,032
Profit before taxation[d]	3,570	1,390	7,285	2,933	1,278	3,126	(287)	4,309	23,604
Allocable taxes	1,664	611	2,560	1,202	321	1,462	3	1,079	8,902
Results of operations	1,906	779	4,725	1,731	957	1,664	(290)	3,230	14,702

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2007 was a profit of $2,704 million after deducting interest of $401 million, taxation of $1,355 million and minority interest of $215 million.

Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	3,570	1,390	7,285	2,933	1,278	3,126	(287)	4,309	23,604
Jointly controlled entities and associates			1	381	21		2,292	9	2,704
Midstream activities	15	13	709	699	(108)	96	(112)	109	1,421
Total profit before interest and tax	3,585	1,403	7,995	4,013	1,191	3,222	1,893	4,427	27,729

[a]This note contains information relating to oil and natural gas exploration and production activities. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia. The group s share of jointly controlled entities and associates activities are excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the results of operations above.

[b]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c]Includes property taxes, other government take and the fair value gain on embedded derivatives of $47 million. The UK region includes a $409 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

[d]Excludes the unwinding of the discount on provisions and payables amounting to $179 million which is included in finance costs in the group income statement.

Notes on financial statements

47. Oil and natural gas exploration and production activities[a] continued

									$ million
									2006
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	32,528	4,951	44,856	9,404	3,569	15,516		6,278	117,102
Unproved properties	423	116	1,443	379	1,155	936	1	137	4,590
	32,951	5,067	46,299	9,783	4,724	16,452	1	6,415	121,692
Accumulated depreciation	22,908	3,175	19,724	4,618	1,709	6,944		1,708	60,786
Net capitalized costs	10,043	1,892	26,575	5,165	3,015	9,508	1	4,707	60,906

The group s share of jointly controlled entities and associates net capitalized costs at 31 December 2006 was $10,870 million.

Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved									
Unproved			74	8	2	70			154
			74	8	2	70			154
Exploration and appraisal costs[b]	132	26	838	135	45	434	73	82	1,765
Development costs	794	214	3,579	820	238	2,356		1,108	9,109
Total costs	926	240	4,491	963	285	2,860	73	1,190	11,028

The group s share of jointly controlled entities and associates costs incurred in 2006 was $1,688 million: in Russia $1,109 million, Rest of Americas $424 million, Asia Pacific $16 million and other $139 million.

Results of operations for the year ended 31

December

Sales and other operating revenues									
Third parties	5,378	628	1,381	2,196	1,159	1,647		768	13,157
Sales between businesses	2,329	1,024	14,572	3,229	807	2,875		7,640	32,476
	7,707	1,652	15,953	5,425	1,966	4,522		8,408	45,633
Exploration expenditure	20	(1)	634	132	11	132	17	100	1,045
Production costs	1,312	145	2,311	638	155	509		238	5,308
Production taxes	492	38	887	295	63			2,079	3,854
Other costs (income)[c]	(867)	90	2,561	478	154	104	32	3,121	5,673
Depreciation, depletion and amortization	1,612	213	2,083	685	175	865		510	6,143
Impairments and (gains) losses on sale of businesses and fixed assets	(450)	(57)	(1,880)	42	(99)	(31)			(2,475)
	2,119	428	6,596	2,270	459	1,579	49	6,048	19,548
Profit before taxation[d]	5,588	1,224	9,357	3,155	1,507	2,943	(49)	2,360	26,085
Allocable taxes	2,567	793	3,136	1,443	472	1,328	3	737	10,479
Results of operations	3,021	431	6,221	1,712	1,035	1,615	(52)	1,623	15,606

The group s share of jointly controlled entities and associates results of operations (including the group s share of total TNK-BP results) in 2006 was a profit of $3,302 million after deducting interest of $324 million, taxation of $1,804 million and minority interest of $193 million.

Exploration and Production segment profit before interest and tax									
Exploration and production activities									
Group (as above)	5,588	1,224	9,357	3,155	1,507	2,943	(49)	2,360	26,085
Jointly controlled entities and associates			1	535	33	1	2,730	2	3,302
Midstream activities	519	154	617	445	(196)	37	(24)	14	1,566
Total profit before interest and tax	6,107	1,378	9,975	4,135	1,344	2,981	2,657	2,376	30,953

[a]This note contains information relating to oil and natural gas exploration and production activities. Midstream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The main midstream activities are the Alaskan transportation facilities, the Forties Pipeline

system and the Central Area Transmission System. The group s share of jointly controlled entities and associates activities is excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above.

[b]Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[c]Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes, other government take and the fair value gain on embedded derivatives $515 million.

[d]Excludes the unwinding of the discount on provisions and payables amounting to $153 million which is included in finance costs in the group income statement.

Additional information for US reporting

Additional information for US reporting
48. Auditor s remuneration for US reporting

			$ million
	2008	2007	2006
Audit fees Ernst & Young			
Group audit	**34**	37	36
Audit-related regulatory reporting	**6**	7	9
Statutory audit of subsidiaries	**17**	19	19
	57	63	64
Fees for other services Ernst & Young			
Further assurance services			
Acquisition and disposal due diligence	**2**	1	3
Pension plan audits	**1**	1	
Other further assurance services	**5**	8	5
Tax services			
Compliance services			1
Advisory services	**2**	2	
	10	12	9

Audit fees for 2008 include $3 million of additional fees for 2007 (2007 $7 million of additional fees for 2006 and 2006 $5 million of additional fees for 2005). Audit fees are included in the income statement within distribution and administration expenses.

Other further assurance services include nil (2007 $1 million and 2006 nil) in respect of advice on accounting, auditing and financial reporting matters; $5 million (2007 $5 million and 2006 $5 million) in respect of non-statutory audits and nil (2007 $2 million and 2006 nil) in respect of project assurance and advice on business and accounting process improvement.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Additional information for US reporting

49. Valuation and qualifying accounts

		Additions			$ million
	Balance at 1 January	Charged to costs and expenses	Charged to other accounts[a]	Deductions	Balance at 31 December
2008					
Fixed assets Investments[b]	**146**	**647**	**143**	**(1)**	**935**
Doubtful debts[b]	**406**	**191**	**(32)**	**(174)**	**391**
2007					
Fixed assets Investments[b]	151	158	2	(165)	146
Doubtful debts[b]	421	175	34	(224)	406
2006					
Fixed assets Investments[b]	172	26	(3)	(44)	151
Doubtful debts[b]	374	158	32	(143)	421

[a]Principally currency transactions.

[b]Deducted in the balance sheet from the assets to which they apply.

50. Computation of ratio of earnings to fixed charges (unaudited)

					$ million, except ratios
For the year ended 31 December	**2008**	2007	2006	2005	2004
Profit before taxation	**34,283**	31,611	35,142	31,421	24,966
Group s share of income in excess of dividends from equity-accounted entities	**(93)**	(1,359)		(710)	(81)
Capitalized interest, net of amortization	**56**	(183)	(341)	(193)	(133)
	34,246	30,069	34,801	30,518	24,752
Fixed charges					
Interest expense	**1,157**	1,110	718	559	440
Rental expense representative of interest	**1,231**	1,033	946	605	619
Capitalized interest	**162**	323	478	351	204

	2,550	2,466	2,142	1,515	1,263
Total adjusted earnings available for payment of fixed charges	**36,796**	32,535	36,943	32,033	26,015
Ratio of earnings to fixed charges	**14.4**	13.2	17.2	21.1	20.6

51. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100% owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the group s share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Canada Finance Company, BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%-owned finance subsidiaries of BP p.l.c.

Additional information for US reporting

51. Condensed consolidating information on certain US subsidiaries continued
Income statement

$ million

For the year ended 31 December					2008
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**6,782**		**361,143**	**(6,782)**	**361,143**
Earnings from jointly controlled entities after interest and tax			**3,023**		**3,023**
Earnings from associates after interest and tax			**798**		**798**
Equity-accounted income of subsidiaries after interest and tax	**469**	**20,295**		**(20,764)**	
Interest and other revenues	**514**	**173**	**1,025**	**(976)**	**736**
Total revenues	**7,765**	**20,468**	**365,989**	**(28,522)**	**365,700**
Gains on sale of businesses and fixed assets			**1,353**		**1,353**
Total revenues and other income	**7,765**	**20,468**	**367,342**	**(28,522)**	**367,053**
Purchases	**895**		**272,869**	**(6,782)**	**266,982**
Production and manufacturing expenses	**1,083**		**28,100**		**29,183**
Production and similar taxes	**2,343**		**4,183**		**6,526**
Depreciation, depletion and amortization	**365**		**10,620**		**10,985**
Impairment and losses on sale of businesses and fixed assets			**1,733**		**1,733**
Exploration expense			**882**		**882**
Distribution and administration expenses	**22**	**28**	**15,469**	**(107)**	**15,412**
Fair value (gain) loss on embedded derivatives			**111**		**111**
Profit before interest and taxation	**3,057**	**20,440**	**33,375**	**(21,633)**	**35,239**
Finance costs	**158**	**169**	**2,089**	**(869)**	**1,547**
Net finance (income) expense relating to pensions and other post-retirement benefits		**(822)**	**231**		**(591)**
Profit before taxation	**2,899**	**21,093**	**31,055**	**(20,764)**	**34,283**
Taxation	**944**	**(64)**	**11,737**		**12,617**
Profit for the year	**1,955**	**21,157**	**19,318**	**(20,764)**	**21,666**

Attributable to					
BP shareholders	**1,955**	**21,157**	**18,809**	**(20,764)**	**21,157**
Minority interest			**509**		**509**
	1,955	**21,157**	**19,318**	**(20,764)**	**21,666**

$ million

For the year ended 31 December					2007
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	5,243		284,365	(5,243)	284,365
Earnings from jointly controlled entities after interest and tax			3,135		3,135
Earnings from associates after interest and tax			697		697
Equity-accounted income of subsidiaries after interest and tax	586	21,201		(21,787)	
Interest and other revenues[a]	758	205	1,166	(1,375)	754
Total revenues	6,587	21,406	289,363	(28,405)	288,951
Gains on sale of businesses and fixed assets	1		2,486		2,487
Total revenues and other income	6,588	21,406	291,849	(28,405)	291,438
Purchases	650		205,359	(5,243)	200,766
Production and manufacturing expenses	897		25,018		25,915
Production and similar taxes	1,052		2,961		4,013
Depreciation, depletion and amortization	388		10,191		10,579
Impairment and losses on sale of businesses and fixed assets			1,679		1,679
Exploration expense			756		756
Distribution and administration expenses	22	921	14,536	(108)	15,371
Fair value (gain) loss on embedded derivatives			7		7
Profit before interest and taxation	3,579	20,485	31,342	(23,054)	32,352
Finance costs[a]	49	381	2,230	(1,267)	1,393
Net finance (income) expense relating to pensions and other post-retirement benefits		(820)	168		(652)
Profit before taxation	3,530	20,924	28,944	(21,787)	31,611
Taxation[a]	1,055	79	9,308		10,442
Profit for the year	2,475	20,845	19,636	(21,787)	21,169

Attributable to					
BP shareholders	2,475	20,845	19,312	(21,787)	20,845
Minority interest			324		324
	2,475	20,845	19,636	(21,787)	21,169

Additional information for US reporting

51. Condensed consolidating information on certain US subsidiaries continued
Income statement continued

$ million

For the year ended 31 December					2006
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,812		265,906	(4,812)	265,906
Earnings from jointly controlled entities after interest and tax			3,553		3,553
Earnings from associates after interest and tax			442		442
Equity-accounted income of subsidiaries after interest and tax	570	23,119		(23,689)	
Interest and other revenues[a]	627	187	1,509	(1,622)	701
Total revenues	6,009	23,306	271,410	(30,123)	270,602
Gains on sale of businesses and fixed assets		105	3,714	(105)	3,714
Total revenues and other income	6,009	23,411	275,124	(30,228)	274,316
Purchases	566		191,429	(4,812)	187,183
Production and manufacturing expenses	814		22,479		23,293
Production and similar taxes	665		2,956		3,621
Depreciation, depletion and amortization	374		8,754		9,128
Impairment and losses on sale of businesses and fixed assets	109		440		549
Exploration expense	14		1,031		1,045
Distribution and administration expenses	20	278	14,264	(115)	14,447
Fair value (gain) loss on embedded derivatives			(608)		(608)
Profit before interest and taxation from continuing operations	3,447	23,133	34,379	(25,301)	35,658
Finance costs[a]	11	702	1,780	(1,507)	986
Net finance (income) expense relating to pensions and other post-retirement benefits		(675)	205		(470)
Profit before taxation from continuing operations	3,436	23,106	32,394	(23,794)	35,142
Taxation[a]	1,005	686	10,825		12,516
Profit from continuing operations	2,431	22,420	21,569	(23,794)	22,626

Profit (loss) from Innovene operations			(25)		(25)
Profit for the year	2,431	22,420	21,544	(23,794)	22,601
Attributable to					
BP shareholders	2,431	22,420	21,258	(23,794)	22,315
Minority interest			286		286
	2,431	22,420	21,544	(23,794)	22,601

[a]Within the 2006 and 2007 income statements, the tax charge for BP Exploration (Alaska) Inc has been reduced by $238 million for 2006 and $26 million for 2007 from the amounts previously disclosed, and the tax charge for Other subsidiaries has been increased by $238 million and $26 million respectively from the amounts previously disclosed. This change has been made to reflect the allocation of tax charges between BP Exploration (Alaska) Inc and other Alaskan subsidiaries in the BP group. As a result of this immaterial change, the profit for the year relating to BP Exploration (Alaska) Inc has increased by $238 million in 2006 and $26 million in 2007 and the profit for the year relating to Other subsidiaries has decreased by $238 million and $26 million respectively. There is no impact on the consolidated group profit for the year. In addition, for Other subsidiaries the amount of interest and other revenues in 2007 has been increased by $789 million (2006, $628 million) and the amount of finance costs has increased by the same amounts. This change has been made to properly reflect interest between group entities. Corresponding adjustments have been to the Eliminations and reclassifications amounts. The BP group amounts are unchanged. This immaterial change has no impact upon profit for the year for Other subsidiaries or BP group.

Additional information for US reporting

51. Condensed consolidating information on certain US subsidiaries continued
Balance sheet

					$ million
At 31 December					**2008**
	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Non-current assets					
Property, plant and equipment	**6,959**		**96,241**		**103,200**
Goodwill			**9,878**		**9,878**
Intangible assets	**243**		**10,017**		**10,260**
Investments in jointly controlled entities			**23,826**		**23,826**
Investments in associates		**2**	**3,998**		**4,000**
Other investments			**855**		**855**
Subsidiaries equity-accounted basis	**3,585**	**111,730**		**(115,315)**	
Fixed assets	**10,787**	**111,732**	**144,815**	**(115,315)**	**152,019**
Loans	**209**	**1,174**	**1,393**	**(1,781)**	**995**
Other receivables			**710**		**710**
Derivative financial instruments			**5,054**		**5,054**
Prepayments			**1,338**		**1,338**
Defined benefit pension plan surpluses		**1,516**	**222**		**1,738**
	10,996	**114,422**	**153,532**	**(117,096)**	**161,854**
Current assets					
Loans			**168**		**168**
Inventories	**198**		**16,623**		**16,821**
Trade and other receivables	**18,302**	**6,129**	**35,745**	**(30,915)**	**29,261**
Derivative financial instruments			**8,510**		**8,510**
Prepayments	**37**		**3,013**		**3,050**
Current tax receivable			**377**		**377**
Cash and cash equivalents	**(10)**	**11**	**8,196**		**8,197**
	18,527	**6,140**	**72,632**	**(30,915)**	**66,384**
Total assets	**29,523**	**120,562**	**226,164**	**(148,011)**	**228,238**
Current liabilities					
Trade and other payables	**4,925**	**2,602**	**57,032**	**(30,915)**	**33,644**

Derivative financial instruments			**8,977**		**8,977**
Accruals		**7**	**6,736**		**6,743**
Finance debt	**55**		**15,685**		**15,740**
Current tax payable	**162**		**2,982**		**3,144**
Provisions			**1,545**		**1,545**
	5,142	**2,609**	**92,957**	**(30,915)**	**69,793**
Non-current liabilities					
Other payables	**398**	**33**	**4,430**	**(1,781)**	**3,080**
Derivative financial instruments			**6,271**		**6,271**
Accruals		**47**	**737**		**784**
Finance debt			**17,464**		**17,464**
Deferred tax liabilities	**1,630**	**322**	**14,246**		**16,198**
Provisions	**1,074**		**11,034**		**12,108**
Defined benefit pension plan and other post-retirement benefit plan deficits			**10,431**		**10,431**
	3,102	**402**	**64,613**	**(1,781)**	**66,336**
Total liabilities	**8,244**	**3,011**	**157,570**	**(32,696)**	**136,129**
Net assets	**21,279**	**117,551**	**68,594**	**(115,315)**	**92,109**
Equity					
BP shareholders equity	**21,279**	**117,551**	**67,788**	**(115,315)**	**91,303**
Minority interest			**806**		**806**
Total equity	**21,279**	**117,551**	**68,594**	**(115,315)**	**92,109**

Additional information for US reporting

51. Condensed consolidating information on certain US subsidiaries continued
Balance sheet continued

					$ million
At 31 December					2007
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,310		91,679		97,989
Goodwill			11,006		11,006
Intangible assets	349		6,303		6,652
Investments in jointly controlled entities			18,113		18,113
Investments in associates		2	4,577		4,579
Other investments			1,830		1,830
Subsidiaries equity-accounted basis	3,117	115,476		(118,593)	
Fixed assets	9,776	115,478	133,508	(118,593)	140,169
Loans	2,151	1,192	1,541	(3,885)	999
Other receivables			968		968
Derivative financial instruments			3,741		3,741
Prepayments			1,083		1,083
Defined benefit pension plan surpluses		7,265	1,649		8,914
	11,927	123,935	142,490	(122,478)	155,874
Current assets					
Loans			165		165
Inventories	202		26,352		26,554
Trade and other receivables[a]	15,986	840	44,422	(23,228)	38,020
Derivative financial instruments			6,321		6,321
Prepayments	24		3,565		3,589
Current tax receivable			705		705
Cash and cash equivalents	(10)	244	3,328		3,562
	16,202	1,084	84,858	(23,228)	78,916
Assets classified as held for sale			1,286		1,286
	16,202	1,084	86,144	(23,228)	80,202
Total assets	28,129	125,019	228,634	(145,706)	236,076

Current liabilities					
Trade and other payables[a]	4,969	3,115	58,296	(23,228)	43,152
Derivative financial instruments			6,405		6,405
Accruals		10	6,630		6,640
Finance debt	55		15,339		15,394
Current tax payable	306		2,976		3,282
Provisions			2,195		2,195
	5,330	3,125	91,841	(23,228)	77,068
Liabilities directly associated with assets classified as held for sale			163		163
	5,330	3,125	92,004	(23,228)	77,231
Non-current liabilities					
Other payables	559	27	4,550	(3,885)	1,251
Derivative financial instruments			5,002		5,002
Accruals		44	915		959
Finance debt			15,651		15,651
Deferred tax liabilities	1,765	1,885	15,565		19,215
Provisions	946		11,954		12,900
Defined benefit pension plan and other post-retirement benefit plan deficits			9,215		9,215
	3,270	1,956	62,852	(3,885)	64,193
Total liabilities	8,600	5,081	154,856	(27,113)	141,424
Net assets	19,529	119,938	73,778	(118,593)	94,652
Equity					
BP shareholders equity	19,529	119,938	72,816	(118,593)	93,690
Minority interest			962		962
Total equity	19,529	119,938	73,778	(118,593)	94,652

[a]Within Current liabilities Trade and other payables, the amount of other payables for BP Exploration (Alaska) Inc. has been reduced by $264 million from the amount previously reported and within Current assets Trade and other receivables the amount of other receivables for other subsidiaries has been reduced by $264 million from the amounts previously reported, with a corresponding change to intercompany eliminations within the Eliminations and reclassifications column. As a result of this immaterial change, the net assets and BP shareholders equity of BP Exploration (Alaska) Inc. have increased by $264 million and the net assets and BP shareholders equity of Other subsidiaries have decreased by $264 million. This change has been made to reflect the allocation of tax liabilities between BP Exploration (Alaska) Inc. and other Alaskan subsidiaries in the BP group. There is no impact on the BP group total equity.

Additional information for US

51. Condensed consolidating information on certain US subsidiaries continued
Cash flow statement

$ million

2008

	Issuer BP Exploration (Alaska) Inc.	**Guarantor BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Net cash provided by operating activities	**6,793**	**12,665**	**35,703**	**(17,066)**	**38,095**
Net cash used in investing activities	**(896)**		**(21,871)**		**(22,767)**
Net cash used in financing activities	**(5,897)**	**(12,898)**	**(8,780)**	**17,066**	**(10,509)**
Currency translation differences relating to cash and cash equivalents			**(184)**		**(184)**
(Decrease) increase in cash and cash equivalents		**(233)**	**4,868**		**4,635**
Cash and cash equivalents at beginning of year	**(10)**	**244**	**3,328**		**3,562**
Cash and cash equivalents at end of year	**(10)**	**11**	**8,196**		**8,197**

$ million

2007

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	3,072	15,403	22,839	(16,605)	24,709
Net cash used in investing activities	(532)	1	(14,306)		(14,837)
Net cash used in financing activities	(2,545)	(15,139)	(7,956)	16,605	(9,035)
Currency translation differences relating to cash and cash equivalents			135		135
(Decrease) increase in cash and cash equivalents	(5)	265	712		972

Cash and cash equivalents at beginning of year	(5)	(21)	2,616		2,590
Cash and cash equivalents at end of year	(10)	244	3,328		3,562

$ million

2006

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	3,522	20,628	29,030	(25,008)	28,172
Net cash used in investing activities	(379)	843	(9,982)		(9,518)
Net cash used in financing activities	(3,141)	(21,495)	(19,443)	25,008	(19,071)
Currency translation differences relating to cash and cash equivalents			47		47
(Decrease) increase in cash and cash equivalents	2	(24)	(348)		(370)
Cash and cash equivalents at beginning of year	(7)	3	2,964		2,960
Cash and cash equivalents at end of year	(5)	(21)	2,616		2,590

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited)
Movements in estimated net proved reserves
For details of BP s governance process for the booking of oil and natural gas reserves, see page 15. BP estimates proved reserves for reporting purposes in accordance with SEC rules and relevant guidance. As currently required, these proved reserve estimates are based on prices and costs as of the date the estimate is made. There was a rapid and substantial decline in oil prices in the fourth quarter of 2008 that was not matched by a similar reduction in operating costs by the end of the year. BP does not expect that these economic conditions will continue. However, our 2008 reserves are calculated on the basis of operating activities that would be undertaken were year-end prices and costs to persist.

									2008
Crude oil[a]									**million barrels**
	UK	**Rest of Europe**	**US**	**Rest of Americas**	**Asia Pacific**	**Africa**	**Russia**	**Other**	**Total**
Subsidiaries									
At 1 January 2008									
Developed	**414**	**105**	**1,882**	**115**	**61**	**256**		**104**	**2,937**
Undeveloped	**123**	**169**	**1,265**	**203**	**77**	**350**		**368**	**2,555**
	537	**274**	**3,147**	**318**	**138**	**606**		**472**	**5,492**
Changes attributable to									
Revisions of previous estimates	**16**	**(11)**	**(212)**	**8**	**16**	**264**		**183**	**264**
Purchases of reserves-in-place									
Discoveries and extensions			**64**	**5**		**173**			**242**
Improved recovery	**39**	**28**	**182**	**8**	**6**	**18**		**40**	**321**
Production[b]	**(63)**	**(16)**	**(191)**	**(26)**	**(14)**	**(101)**		**(44)**	**(455)**
Sales of reserves-in-place				**(199)**					**(199)**
	(8)	**1**	**(157)**	**(204)**	**8**	**354**		**179**	**173**
At 31 December 2008[c]									
Developed	**410**	**81**	**1,717**	**58**	**77**	**464**		**174**	**2,981**
Undeveloped	**119**	**194**	**1,273**	**56**	**69**	**496**		**477**	**2,684**
	529	**275**	**2,990[e]**	**114**	**146**	**960**		**651**	**5,665**

Equity-accounted entities (BP share)						
At 1 January 2008						
Developed	**328**	**1**		**2,094**	**573**	**2,996**
Undeveloped	**243**			**1,137**	**205**	**1,585**
	571	**1**		**3,231**	**778**	**4,581**
Changes attributable to						
Revisions of previous estimates	**(3)**		**11**	**217**	**(1)**	**224**
Purchases of reserves-in-place	**199**					**199**
Discoveries and extensions	**13**			**26**		**39**
Improved recovery	**62**					**62**
Production	**(34)**			**(302)**	**(80)**	**(416)**
Sales of reserves-in-place				**(1)**		**(1)**
	237		**11**	**(60)**	**(81)**	**107**
At 31 December 2008[d]						
Developed	**399**	**1**		**2,227**	**498**	**3,125**
Undeveloped	**409**		**11**	**944**	**199**	**1,563**
	808	**1**	**11**	**3,171**	**697**	**4,688**

[a]Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]Excludes NGLs from processing plants in which an interest is held of 19 thousand barrels per day.

[c]Includes 807 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 36 million barrels of NGLs. Also includes 216 million barrels of crude oil in respect of the 6.80% minority interest in TNK-BP.

[e]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 54 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Movements in estimated net proved reserves continued

									2008
Natural gas[a]									**billion cubic feet**
	UK	**Rest of Europe**	**US**	**Rest of Americas**	**Asia Pacific**	**Africa**	**Russia**	**Other**	**Total**
Subsidiaries									
At 1 January 2008									
Developed	**2,049**	**63**	**10,670**	**3,683**	**1,822**	**990**		**583**	**19,860**
Undeveloped	**553**	**410**	**4,705**	**8,394**	**4,817**	**1,410**		**981**	**21,270**
	2,602	**473**	**15,375**	**12,077**	**6,639**	**2,400**		**1,564**	**41,130**
Changes attributable to									
Revisions of previous estimates	**23**	**(8)**	**(2,063)**	**(405)**	**326**	**142**		**35**	**(1,950)**
Purchases of reserves-in-place			**183**						**183**
Discoveries and extensions			**549**	**1,073**		**82**		**37**	**1,741**
Improved recovery	**77**	**9**	**1,322**	**175**	**56**	**6**		**54**	**1,699**
Production[b]	**(298)**	**(11)**	**(834)**	**(1,040)**	**(264)**	**(198)**		**(150)**	**(2,795)**
Sales of reserves-in-place				**(3)**					**(3)**
	(198)	**(10)**	**(843)**	**(200)**	**118**	**32**		**(24)**	**(1,125)**
At 31 December 2008[c]									
Developed	**1,822**	**61**	**9,059**	**3,975**	**2,482**	**1,050**		**507**	**18,956**
Undeveloped	**582**	**402**	**5,473**	**7,902**	**4,275**	**1,382**		**1,033**	**21,049**
	2,404	**463**	**14,532**	**11,877**	**6,757**	**2,432**		**1,540**	**40,005**
Equity-accounted entities (BP share)									
At 1 January 2008									
Developed				**1,478**	**39**		**808**	**148**	**2,473**
Undeveloped				**831**	**37**		**353**	**76**	**1,297**

	2,309	**76**		**1,161**	**224**	**3,770**
Changes attributable to						
Revisions of previous estimates	**(96)**	**(2)**	**182**	**1,273**		**1,357**
Purchases of reserves-in-place	**3**					**3**
Discoveries and extensions	**192**					**192**
Improved recovery	**301**	**11**				**312**
Production[b]	**(188)**	**(12)**		**(221)**	**(10)**	**(431)**
Sales of reserves-in-place						
	212	**(3)**	**182**	**1,052**	**(10)**	**1,433**
At 31 December 2008[d]						
Developed	**1,498**	**37**		**1,560**	**139**	**3,234**
Undeveloped	**1,023**	**36**	**182**	**653**	**75**	**1,969**
	2,521	**73**	**182**	**2,213**	**214**	**5,203**

[a]Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]Includes 193 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 44 billion cubic feet in equity-accounted entities and excludes 16.9 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c]Includes 3,108 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 131 billion cubic feet of natural gas in respect of the 5.92% minority interest in TNK-BP.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Movements in estimated net proved reserves continued

Crude oil[a]									2007 million barrels
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2007									
Developed	458	189	1,916	130	67	193		88	3,041
Undeveloped	146	97	1,292	237	86	512		482	2,852
	604	286	3,208	367	153	705		570	5,893
Changes attributable to									
Revisions of previous estimates	(1)	(25)	18	(29)	(7)	(133)		(27)	(204)
Purchases of reserves-in-place			25					8	33
Discoveries and extensions		31	60	1	2	93			187
Improved recovery	7	1	99	6	5	12		1	131
Production[b]	(73)	(19)	(169)	(27)	(15)	(71)		(80)	(454)
Sales of reserves-in-place			(94)						(94)
	(67)	(12)	(61)	(49)	(15)	(99)		(98)	(401)
At 31 December 2007[c]									
Developed	414	105	1,882	115	61	256		104	2,937
Undeveloped	123	169	1,265	203	77	350		368	2,555
	537	274	3,147[f]	318	138	606		472	5,492
Equity-accounted entities (BP share)[d]									
At 1 January 2007									
Developed				221	1		2,200	520	2,942
Undeveloped				139			644	163	946

	360	1	2,844	683	3,888
Changes attributable to					
Revisions of previous estimates	178		413	167	758
Purchases of reserves-in-place			16		16
Discoveries and extensions	2		283		285
Improved recovery	59			1	60
Production	(28)		(304)	(73)	(405)
Sales of reserves-in-place			(21)		(21)
	211		387	95	693
At 31 December 2007[e]					
Developed	328	1	2,094	573	2,996
Undeveloped	243		1,137	205	1,585
	571	1	3,231	778	4,581

[a]Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]Excludes NGLs from processing plants in which an interest is held of 54 thousand barrels per day.

[c]Includes 739 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]The BP group holds interests, through associates, in onshore and offshore concessions in Abu Dhabi, expiring in 2014 and 2018 respectively. During the second quarter of 2007, we updated our reporting policy in Abu Dhabi to be consistent with general industry practice and as a result have started reporting production and reserves there gross of production taxes. This change resulted in an increase in our reserves of 153 million barrels and in our production of 33mb/d.

[e]Includes 26 million barrels of NGLs. Also includes 210 million barrels of crude oil in respect of the 6.51% minority interest in TNK-BP.

[f]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 98 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Movements in estimated net proved reserves continued

									2007
Natural gas[a]									billion cubic feet
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2007									
Developed	1,968	242	10,438	3,932	1,359	1,032		331	19,302
Undeveloped	825	56	4,660	9,194	5,202	1,675		1,254	22,866
	2,793	298	15,098	13,126	6,561	2,707		1,585	42,168
Changes attributable to									
Revisions of previous estimates	93	(37)	744	(276)	140	(146)		(21)	497
Purchases of reserves-in-place			23					109	132
Discoveries and extensions		293	95	249	88	17			742
Improved recovery	15	1	326	32	111	9		5	499
Production[b]	(299)	(14)	(879)	(1,047)	(261)	(187)		(114)	(2,801)
Sales of reserves-in-place		(68)	(32)	(7)					(107)
	(191)	175	277	(1,049)	78	(307)		(21)	(1,038)
At 31 December 2007[c]									
Developed	2,049	63	10,670	3,683	1,822	990		583	19,860
Undeveloped	553	410	4,705	8,394	4,817	1,410		981	21,270
	2,602	473	15,375	12,077	6,639	2,400		1,564	41,130
Equity-accounted entities (BP share)									
At 1 January 2007									
Developed				1,460	52		1,087	170	2,769
Undeveloped				735	23		184	52	994

	2,195	75	1,271	222	3,763
Changes attributable to					
Revisions of previous estimates	73	(2)	61	11	143
Purchases of reserves-in-place			8		8
Discoveries and extensions	22				22
Improved recovery	195	16			211
Production[b]	(176)	(13)	(179)	(9)	(377)
Sales of reserves-in-place					
	114	1	(110)	2	7
At 31 December 2007[d]					
Developed	1,478	39	808	148	2,473
Undeveloped	831	37	353	76	1,297
	2,309	76	1,161	224	3,770

[a]Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]Includes 202 billion cubic feet of natural gas consumed in operations, 161 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 10.9 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c]Includes 3,211 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 68 billion cubic feet of natural gas in respect of the 5.88% minority interest in TNK-BP.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Movements in estimated net proved reserves continued

									2006
Crude oil[a]									million barrels
	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2006									
Developed	496	225	1,984	215	70	142		69	3,201
Undeveloped	184	86	1,429	286	95	536		543	3,159
	680	311	3,413	501	165	678		612	6,360
Changes attributable to									
Revisions of previous estimates	(3)	(11)	(108)	(9)		2		16	(113)
Purchases of reserves-in-place									
Discoveries and extensions	3		48		1	67			119
Improved recovery	26	9	95	13	4	22			169
Production[b]	(92)	(23)	(178)	(39)	(17)	(64)		(58)	(471)
Sales of reserves-in-place	(10)		(62)	(99)					(171)
	(76)	(25)	(205)	(134)	(12)	27		(42)	(467)
At 31 December 2006[c]									
Developed	458	189	1,916	130	67	193		88	3,041
Undeveloped	146	97	1,292	237	86	512		482	2,852
	604	286	3,208[e]	367	153	705		570	5,893
Equity-accounted entities (BP share)									
At 1 January 2006									
Developed				207	1		1,688	590	2,486
Undeveloped				124			431	164	719

	331	1	2,119	754	3,205
Changes attributable to					
Revisions of previous estimates	(2)		1,215	(8)	1,205
Purchases of reserves-in-place	28				28
Discoveries and extensions	1				1
Improved recovery	34				34
Production	(28)		(320)	(63)	(411)
Sales of reserves-in-place	(4)		(170)		(174)
	29		725	(71)	683
At 31 December 2006[d]					
Developed	221	1	2,200	520	2,942
Undeveloped	139		644	163	946
	360	1	2,844	683	3,888

[a]Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option to make lifting and sales arrangements independently.

[b]Excludes NGLs from processing plants in which an interest is held of 55 thousand barrels per day.

[c]Includes 779 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 28 million barrels of NGLs. Also includes 179 million barrels of crude oil in respect of the 6.29% minority interest in TNK-BP.

[e]Proved reserves in the Prudhoe Bay field in Alaska include an estimated 81 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Movements in estimated net proved reserves continued

2006

Natural gas[a] billion cubic feet

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
At 1 January 2006									
Developed	2,382	245	11,184	3,560	1,459	934		281	20,045
Undeveloped	904	80	4,198	10,504	5,375	2,000		1,342	24,403
	3,286	325	15,382	14,064	6,834	2,934		1,623	44,448
Changes attributable to									
Revisions of previous estimates	(343)	11	(922)	(291)	(92)	(69)		33	(1,673)
Purchases of reserves-in-place									
Discoveries and extensions	101		116		21	5		2	245
Improved recovery	144		1,755	344	71	6		9	2,329
Production[b]	(370)	(38)	(941)	(982)	(273)	(169)		(82)	(2,855)
Sales of reserves-in-place	(25)		(292)	(9)					(326)
	(493)	(27)	(284)	(938)	(273)	(227)		(38)	(2,280)
At 31 December 2006[c]									
Developed	1,968	242	10,438	3,932	1,359	1,032		331	19,302
Undeveloped	825	56	4,660	9,194	5,202	1,675		1,254	22,866
	2,793	298	15,098	13,126	6,561	2,707		1,585	42,168
Equity-accounted entities (BP share)									
At 1 January 2006									
Developed				1,492	50		1,089	130	2,761

Undeveloped	848	26	169	52	1,095
	2,340	76	1,258	182	3,856
Changes attributable to					
Revisions of previous estimates	7	13	217	47	284
Purchases of reserves-in-place					
Discoveries and extensions	23				23
Improved recovery	73	1			74
Production[b]	(171)	(15)	(204)	(7)	(397)
Sales of reserves-in-place	(77)				(77)
	(145)	(1)	13	40	(93)
At 31 December 2006[d]					
Developed	1,460	52	1,087	170	2,769
Undeveloped	735	23	184	52	994
	2,195	75	1,271	222	3,763

[a]Proved reserves exclude royalties due to others, whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option to make lifting and sales arrangements independently.

[b]Includes 178 billion cubic feet of natural gas consumed in operations, 147 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 8.3 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.

[c]Includes 3,537 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

[d]Includes 99 billion cubic feet of natural gas in respect of the 7.77% minority interest in TNK-BP.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measures of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 69 Disclosures about Oil and Gas Producing Activities .

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of year-end crude oil and natural gas prices and exchange rates. Furthermore, both reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Other	Total
At 31 December 2008								
Future cash inflows[a]	**36,400**	**13,800**	**165,800**	**32,700**	**28,400**	**40,400**	**27,200**	**344,700**
Future production cost[b]	**18,100**	**6,300**	**80,400**	**9,900**	**12,100**	**11,600**	**10,400**	**148,800**
Future development cost[b]	**3,300**	**2,900**	**25,600**	**8,500**	**3,800**	**10,900**	**6,900**	**61,900**
Future taxation[c]	**7,300**	**2,300**	**17,500**	**6,000**	**3,200**	**6,600**	**2,000**	**44,900**
Future net cash flows	**7,700**	**2,300**	**42,300**	**8,300**	**9,300**	**11,300**	**7,900**	**89,100**
10% annual discount[d]	**2,200**	**1,200**	**21,000**	**3,900**	**4,600**	**5,500**	**3,500**	**41,900**
Standardized measure of discounted future net cash flows[e]	**5,500**	**1,100**	**21,300**	**4,400**	**4,700**	**5,800**	**4,400**	**47,200**
At 31 December 2007								
Future cash inflows[a]	72,100	29,500	350,100	67,700	47,600	63,300	49,400	679,700
Future production cost[b]	27,500	7,500	109,800	17,900	12,800	9,900	8,500	193,900
Future development cost[b]	4,000	3,300	21,900	6,500	4,100	8,300	3,500	51,600
Future taxation[c]	20,200	13,000	71,600	21,700	9,700	17,100	8,700	162,000
Future net cash flows	20,400	5,700	146,800	21,600	21,000	28,000	28,700	272,200
10% annual discount[d]	6,500	2,800	76,000	9,500	10,300	9,400	11,500	126,000
Standardized measure of discounted future net cash flows[e]	13,900	2,900	70,800	12,100	10,700	18,600	17,200	146,200

At 31 December 2006								
Future cash inflows[a]	45,300	18,200	218,900	46,800	36,800	47,700	36,200	449,900
Future production cost[b]	20,700	4,700	71,300	14,900	9,400	8,700	7,200	136,900
Future development cost[b]	3,300	1,500	18,600	4,900	3,800	6,600	3,900	42,600
Future taxation[c]	10,300	9,400	43,100	12,900	7,000	10,600	5,800	99,100
Future net cash flows	11,000	2,600	85,900	14,100	16,600	21,800	19,300	171,300
10% annual discount[d]	3,200	1,000	45,600	6,200	9,000	8,400	7,300	80,700
Standardized measure of discounted future net cash flows[e]	7,800	1,600	40,300	7,900	7,600	13,400	12,000	90,600

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	2008	2007	2006
Sales and transfers of oil and gas produced, net of production costs	**(43,600)**	(28,300)	(35,800)
Previously estimated development costs incurred during the year	**9,400**	9,400	8,200
Extensions, discoveries and improved recovery, less related costs	**4,400**	12,300	7,900
Net changes in prices and production cost	**(146,800)**	102,100	(43,900)
Revisions of previous reserves estimates	**1,200**	(12,200)	(9,500)
Net change in taxation	**69,400**	(28,300)	32,200
Future development costs	**(7,400)**	(7,800)	(7,000)
Net change in purchase and sales of reserves-in-place	**(200)**	(700)	(2,500)
Addition of 10% annual discount	**14,600**	9,100	12,800
Total change in the standardized measure during the year[f]	**(99,000)**	55,600	(37,600)

[a]The year-end marker prices used were Brent $36.55/bbl, Henry Hub $5.63/mmBtu (2007 Brent $96.02/bbl, Henry Hub $7.10/mmBtu and 2006 Brent $58.93/bbl, Henry Hub $5.52/mmBtu).

[b]Production costs, which include production taxes and development costs relating to future production of proved reserves, are based on year-end cost levels and assume continuation of existing economic conditions. Future decommissioning costs are included.

[c]Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d]Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e]Minority interest in BP Trinidad and Tobago LLC amounted to $900 million at 31 December 2008 ($2,300 million at 31 December 2007 and $1,300 million at 31 December 2006).

[f]Total change in the standardized measure during the year includes the effect of exchange rate movements.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued
Equity-accounted entities
In addition, at 31 December 2008, the group s share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $9,000 million ($28,300 million at 31 December 2007 and $14,700 million at 31 December 2006), excluding minority interest.

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.
Crude oil and natural gas production
The following table shows crude oil and natural gas production for the years ended 31 December 2008, 2007 and 2006.

Production for the year[a]

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiaries									
Crude oil[b]									thousand barrels per day
2008	**173**	**43**	**538**	**75**	**37**	**277**		**120**	**1,263**
2007	201	51	513	82	41	195		221	1,304
2006	253	61	547	108	44	177		161	1,351
Natural gas[c]									million cubic feet per day
2008	**759**	**23**	**2,157**	**2,777**	**699**	**484**		**378**	**7,277**
2007	768	29	2,174	2,798	699	468		286	7,222
2006	936	91	2,376	2,645	727	430		207	7,412
Equity-accounted entities (BP share)									
Crude oil[b]									thousand barrels per day
2008				**92**	**1**		**826**	**219**	**1,138**
2007				77	1		832	200	1,110
2006				77	1		876	170	1,124
Natural gas[c]									million cubic feet per day

2008	**454**	**31**	**564**	**8**	**1,057**
2007	429	33	451	8	921
2006	416	37	544	8	1,005

[a]Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[b]Crude oil includes natural gas liquids and condensate.

[c]Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2008. A gross well or acre is one in which a whole or fractional working interest is owned, while the number of net wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Number of productive wells at 31 December 2008										
Oil wells[a]	gross	**273**	**81**	**5,960**	**3,695**	**250**	**669**	**19,991**	**1,622**	**32,541**
net		**147**	**25**	**2,120**	**2,023**	**108**	**544**	**8,503**	**268**	**13,738**
Gas wells[b]	gross	**310**		**20,913**	**2,326**	**466**	**99**	**44**	**134**	**24,292**
net		**142**		**11,948**	**1,397**	**166**	**45**	**22**	**89**	**13,809**

[a]Includes approximately 966 gross (255 net) multiple completion wells (more than one formation producing into the same well bore).

[b]Includes approximately 2,631 gross (1,737 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

Supplementary information on oil and natural gas (unaudited)

Supplementary information on oil and natural gas (unaudited) continued

		UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Oil and natural gas acreage at 31 December 2008										Thousands of acres
Developed	gross	**390**	**64**	**7,657**	**3,151**	**1,251**	**500**	**4,072**	**1,876**	**18,961**
net		**193**	**18**	**4,783**	**1,414**	**327**	**212**	**1,768**	**692**	**9,407**
Undeveloped[a]	gross	**1,615**	**519**	**7,733**	**15,586**	**7,433**	**21,524**	**10,079**	**14,832**	**79,321**
net		**916**	**234**	**5,332**	**9,081**	**2,782**	**16,009**	**4,544**	**6,098**	**44,996**

[a]Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	UK	Rest of Europe	US	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
2008									
Exploratory									
Productive	**0.8**		**2.4**	**4.4**	**1.1**	**4.3**	**12.5**		**25.5**
Dry		**0.5**	**0.9**	**0.5**	**0.4**	**2.6**	**23.0**	**0.5**	**28.4**
Development									
Productive	**6.6**	**0.5**	**379.8**	**140.8**	**23.3**	**18.6**	**10.0**	**26.6**	**606.2**
Dry	**0.2**		**1.1**	**3.8**	**0.8**	**1.5**	**19.5**	**1.3**	**28.2**
2007									
Exploratory									
Productive	1.6		4.1	0.5	1.1	6.1	16.0	1.7	31.1
Dry			0.7	0.5	0.4	1.6	9.0	1.0	13.2
Development									
Productive	0.4	0.8	401.2	46.0	13.8	15.3	246.0	15.8	739.3
Dry	0.6		4.2	8.8			9.5		23.1
2006									
Exploratory									
Productive	0.1	0.1	2.9	0.5	1.0	3.2	15.6	1.4	24.8

Dry			7.4	1.0	1.5	0.5	5.7	0.3	16.4
Development									
Productive	4.9	1.6	418.8	154.0	12.4	23.8	227.2	14.5	857.2
Dry			4.5	5.0	0.2		20.8	1.0	31.5

Drilling and production activities in progress
The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as at 31 December 2008. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	UK	**Rest of Europe**	**US**	**Rest of Americas**	**Asia Pacific**	**Africa**	**Russia**	**Other**	**Total**
At 31 December 2008									
Exploratory									
Gross	**2.0**		**27.0**	**5.0**	**1.0**	**4.0**	**7.0**	**3.0**	**49.0**
Net	**0.2**		**12.8**	**2.8**	**0.2**	**2.6**	**3.0**	**2.3**	**23.9**
Development									
Gross	**8.0**	**2.0**	**480.0**	**27.0**	**8.0**	**15.0**	**20.0**	**20.0**	**580.0**
Net	**4.8**	**0.5**	**291.5**	**16.1**	**3.2**	**6.1**	**7.5**	**5.6**	**335.3**

Miscellaneous terms

In this document, unless the context otherwise requires, the following terms shall have the meaning set out below.

ADR
American depositary receipt.

ADS
American depositary share.

AGM
Annual general meeting.

Amoco
The former Amoco Corporation and its subsidiaries.

Atlantic Richfield
Atlantic Richfield Company and its subsidiaries.

Associate
An entity, including an unincorporated entity such as a partnership, over which the group has significant influence and that is neither a subsidiary nor a joint venture. Significant influence is the power to participate in the financial and operating policy decisions of an entity but is not control or joint control over those policies.

Barrel
42 US gallons.

b/d
barrels per day.

boe
barrels of oil equivalent.

BP, BP group or the group
BP p.l.c. and its subsidiaries.

Burmah Castrol
Burmah Castrol PLC and its subsidiaries.

Cent or c
One-hundredth of the US dollar.

The company
BP p.l.c.

Dollar or $
The US dollar.

EU
European Union.

Gas
Natural gas.

Hydrocarbons
Crude oil and natural gas.

IFRS
International Financial Reporting Standards.

Joint control
Joint control is the contractually agreed sharing of control over an economic activity, and exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the parties sharing control (the venturers).

Joint venture
A contractual arrangementwhereby two or more parties undertake an economic activity that is subject to joint control.

Jointly controlled asset
A joint venture where the venturers jointly control, and often have a direct ownership interest in the assets of the venture. The assets are used to obtain benefits for the venturers. Each venturer may take a share of the output from the assets and each bears an agreed share of the expenses incurred.

Jointly controlled entity
A joint venture that involves the establishment of acorporation, partnership or other entity in which each venturer has an interest. A contractual arrangement between the venturers establishes joint control over the economic activity of the entity.

Liquids
Crude oil, condensate and natural gas liquids.

LNG
Liquefied natural gas.

London Stock Exchange or LSE
London Stock Exchange plc.

LPG
Liquefied petroleum gas.

mb/d
thousand barrels per day.

mboe/d
thousand barrels of oil equivalent per day.

mmBtu
million British thermal units.

mmboe
million barrels of oil equivalent.

mmcf
million cubic feet.

mmcf/d
million cubic feet per day.

MTBE
Methyl tertiary butyl ether.

MW
Megawatt.

NGLs
Natural gas liquids.

OPEC
Organization of Petroleum Exporting Countries.

Ordinary shares
Ordinary fully paid shares in BP p.l.c. of 25c each.

Pence or p
One-hundredth of a pound sterling.

Pound, sterling or £
The pound sterling.

Preference shares
Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of £1 each.

PSA
Production-sharing agreement.

SEC
The United States Securities and Exchange Commission.

Subsidiary
An entity that is controlled by the BP group. Control is the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities.

Tonne
2,204.6 pounds.

UK
United Kingdom of Great Britain and Northern Ireland.

US
United States of America.

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)
/s/D.J.JACKSON
D.J.Jackson
Company Secretary
Dated: 4 March 2009